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Further Developing Europe's Power Market
for Large Scale Integration of Wind Power

Assessment of increasing capacity on selected transmission corridors

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1 INTRODUCTION

This report presents the main activity of Work Package 6 (WP6) in the TradeWind project. The main aim of the work package is to develop relevant proposals for offshore and onshore grid reinforcements based on an evaluation of the effect on the power flows. The analyses presented in this report are based on the developed model of the European power system and the collected TradeWind data on load, generation and grids (WP3). The simulations are carried out using the Power System Simulation Tool (PSST) which runs an optimal power flow problem for a given power system model for each hour of a year. The optimal power flow minimises the total generation cost, using a simplified DC power flow representation and with the assumption of a perfect market.

The report is organised as follows:

- Chapter 2 describes presently available technologies that can provide power flow control on AC lines, and briefly discuss the relevance of such solutions, particularly in relation to large scale integration of wind power (RISØ).
- Chapter 3 summarizes the grid upgrade scenarios that are proposed based on an assessment of increasing capacity on critical transmission corridors. Reinforcements were done based on sensitivity of branch and HVDC capacity in an attempt to reduce the bottleneck cost caused by large scale integration of wind as well as redistribution of generation to lower cost production units in general. Branch sensitivity refers to the reduction in the objective function of the market model (in our case fuel cost savings) by increasing the branch capacity by 1 MW. Sensitivity of power line capacity is defined and described in more detail in TradeWind deliverable D3.2 [2].
- Chapter 4 presents the details of the study that led to the grid upgrade scenarios which are summarized in Chapter 3. A bottleneck cost analysis is included for the TradeWind years 2010-2030, identifying the contribution of wind to the total bottleneck costs in the system, referred to a European system where all congestions are removed (copperplate model).
- Chapter 5 comprises the offshore grid analysis that was done based on more detailed information on offshore wind locations and capacities than available in the original TradeWind wind power capacity scenarios. The benefits of building a meshed offshore grid in the North Sea are assessed using the TradeWind grid model, and comparing total generating costs, bottleneck costs and amounts of discarded wind to a base case with radial connection of all offshore wind farms. Section 5.5

(KEMA) presents some ideas of building a more strongly meshed offshore grid.
- Chapter 6 gives a discussion of the methodology, models and data used in this study while Chapter 7 summarizes the main conclusions from the work package.

Detailed data on grid upgrades, grid constraints and bottleneck cost calculations are given in Appendix 1 and Appendix 2. Appendix 3 to 5 supplements Chapter 5 with details regarding offshore wind and offshore grid scenarios. Appendix 6 gives a short overview of model updates that has been done after reporting WP3 [1], [2]. Appendix 7 (KEMA) gives an overview of planned grid extensions within Europe.

2 POWER FLOW CONTROL OPTIONS

Whereas the power flow in DC transmission connections can be controlled, the power flow in AC transmission systems is flowing according to physical laws, given the network and the distribution of loads and generation. This section will describe presently available technologies that can provide power flow control on AC lines, and briefly discuss the relevance of such solutions, particularly in relation to large scale integration of wind power.

Obviously, the lack of power flow controllability is only relevant for meshed networks, because there is only one way for the power to flow in radial networks. Still, large transmission systems are normally meshed, as is the case for the large European transmission networks, i.e. the UCTE system and the Nordel system.

The lack of controllability can sometimes lead to congestions of a possible transmission line, while there is still capacity on alternative lines. Since large scale wind power changes distribution of the generation in the grid, the growth of wind power can increase the feasibility of AC power flow control. An example of this was shown in [8], where increased wind power generation in mid Norway would cause overload of the corridor to Sweden, while there is still free capacity on the corridor to south Norway. One option in that case would be to reduce the hydro generation in mid Norway when the wind speeds are high, but according to the studies in [8], this would not be the optimal market solution if the AC flow could be controlled. Consequently, it may be feasible to control the flow in certain AC lines, even if it would cost investment in auxiliary equipment.

Flexible AC Transmission Systems (FACTS) are widely used to enhance the stability in power systems, but some FACTS solutions also support power flow control [9].

The principle of AC line power flow control is illustrated generally in Figure 2, where a transmission line with reactance X is connecting the two points with voltages U_1 and U_2. From network theory it is known that the line power flow is approximately proportional to the angle δ between the voltages on sending and receiving ends of the line and inverse proportional to the line reactance:

$$P \approx \frac{|U_1||U_2|}{X}\sin(\delta) \qquad (1)$$

From (1) it is seen that the steady state power flow can be influenced by different control actions, like:

- Voltage control
- Line impedance control
- Phase angle control

Voltage control

Voltage control can be performed by controllable reactive power compensation, e.g. through Static Var Compensators (SVCs) or static Synchronous Compensators (STATCOMs). These devices are important for voltage control as such, and they are frequently used for power system stability improvements, but it is easily seen from equation (1) that very large voltage variations are needed to effectively control steady state power flows.

Line impedance control

The second and more effective option is to influence the line reactance (X) directly. The most widely used options for this are Thyristor-Switched Series Capacitors (TSSC) or the Thyristor-Controlled Series Capacitor (TCSC). The TSSC consists of a number of series connected capacitors that can be by-passed (shunted) by thyristor switches. The TCSC is a capacitive reactance compensator which consists of a series capacitor bank shunted by a thyristor-controlled reactor in order to provide a smoothly variable series capacitive reactance X_C. The line impedance can be controlled continuously by controlling the firing angle of the thyristors. One drawback of this solution is that low order harmonics are inevitable.

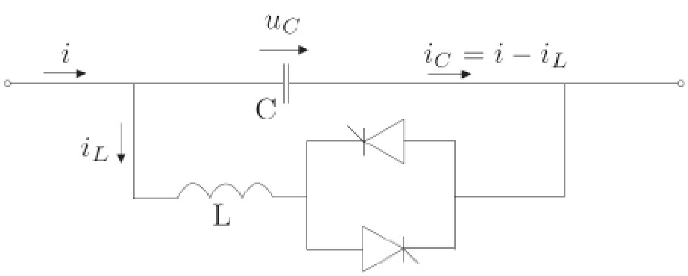

Figure 1. Simplified circuit diagram of a Thyristor-Controlled Series Capacitor (TCSC).

Phase angle control

The most effective way of controlling power flows in a transmission line is to influence the angle difference (δ) between the sending and receiving end voltages. This can be done by providing a serial Voltage U_q as illustrated in Figure 2.

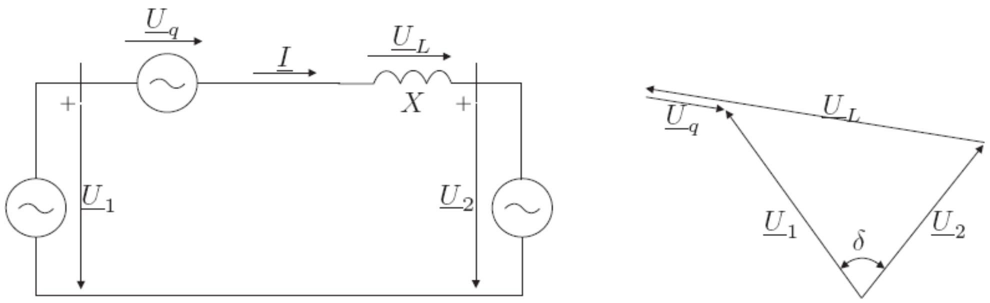

Figure 2. Principle of AC power flow control

The serial voltage *Uq* can be provided by different technologies. The most common – and probably the least costly – technology is phase shift transformers. The principle of this solution is shown in Figure 3. A series transformer in each line is fed by a shunt transformer providing the voltage between the two other lines, which ensures that the serial transformer voltage is perpendicular to the line voltage. The size of the serial voltage can be controlled by tap changers on the shunt transformer. Several manufacturers provide such phase shift transformer (PST) technology, and several countries have already installed or are planning to install PST's [9][10][11][12].

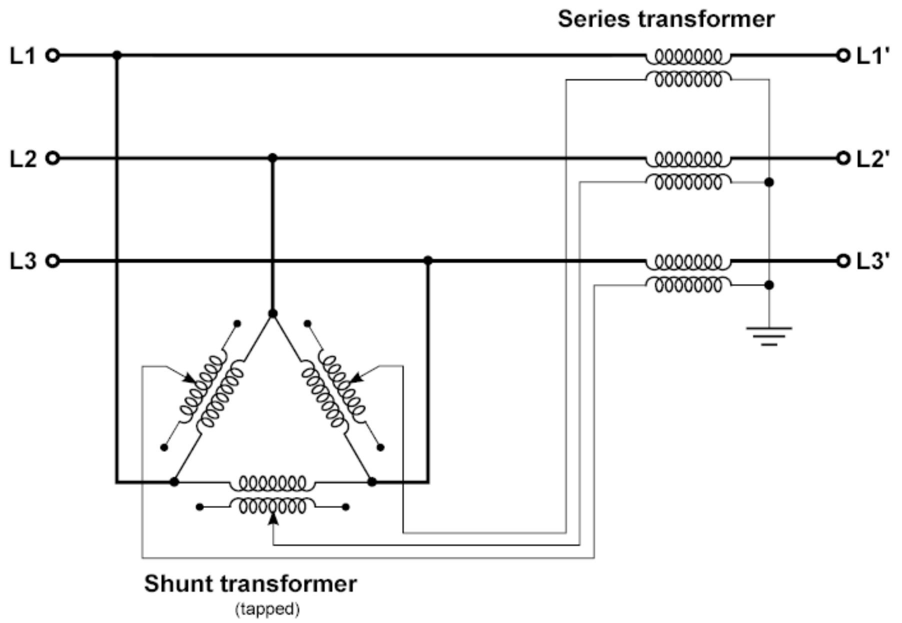

Figure 3. Simplified circuit diagram of a phase shift transformer

A more flexible solution is the Static Synchronous Series Compensator (SSSC). The SSSC is a static synchronous generator (i.e. a power converter connected to the lines with series transformers) operated without an external electric energy source as a series compensator for the purpose of increasing or decreasing the overall reactive voltage drop across the line and thereby controlling the transmitted electric power. Like the TCSC, the SSSC can be controlled continuously, but on top of that, it can provide inductive as well as capacitive voltage change, and the low order harmonics can be eliminated.

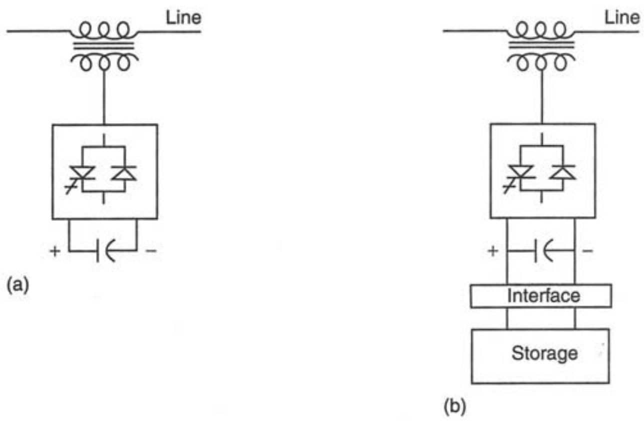

Figure 4. Static Synchronous series Compensator (SSSC) without (a) or with (b) an external energy storage [15].

The most advanced and flexible solutions (but also the most expensive ones) comprise the Unified Power Flow Controller (UPFC) and other *combined* compensators. The UPFC can be seen to consist of a shunt connected converter (a STATCOM) and a series connected converter (SSSC) that is connected to the same dc link via a dc capacitor bank. This device is able to control voltages and at the same time power can be transmitted through the dc link to provide a fully flexible voltage injection (*Uq*) through the series transformer.

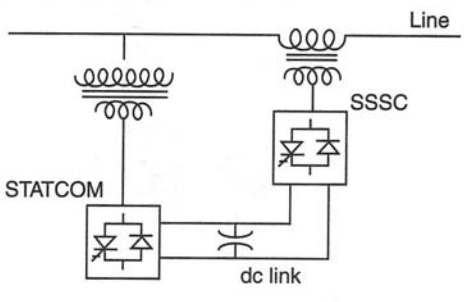

Figure 5. Unified Power Flow Controller (UPFC) [15].

Mechanically switched phase shifters or FACTS devices can be used to ensure that existing transmission lines are utilised to the maximum, which is an important issue, taking into account the reluctance and long term project implementation which is normally associated with reinforcement of transmission systems. The original aim was to emulate the operation of power flow control options in the power system simulation tool PSST and thus study possible market benefits that can be obtained by that. However, this would have required substantial model development work in order to implement the new functionalities and model extensions. It was therefore decided to put emphasis on the analysis of HVDC links as these can be regarded as ideal FACTS devices with full power control capabilities. The effect of power flow control by phase shifters or FACTS devices can thus be analysed and evaluated as an HVDC link with limited controllability.

3 GRID UPGRADE SCENARIOS

3.1 General trends in Europe

Transmission system operators (TSO) are nowadays continuously working on expanding their electricity network. In the 1980s the electricity demand was decreasing and expected to decrease further in many countries, which resulted in less upgrading of networks in terms of capacity. Nowadays the electricity demand is rapidly rising and grid operators invest in new connectors, both national and international ones.

Another concern for the TSOs is the upcoming decentralized generation of renewable power, such as wind energy. Many wind farms are being built or planned in coastal and remote areas, but the existing network might not be built for such amount of electricity. Also the stochastic behaviour of wind energy is an important aspect of dimensioning the network.

As can be seen in the UCTE Transmission Development plan [5], virtually every continental European country reports projects on upgrading its transmission network. Not only AC overhead lines are being built, but also some prestigious submarine HVDC links across long distances. This amount of projects indicates that the grid within Europe needs immediate upgrade.

In the 27 member states of the EU, installed capacity of electricity generation plants rose by 17% the last decade. The prediction is that this trend will continue in the near future. In the next 10 years, UCTE predicts that the new installed generation capacity would be approximately 220 GW within the UCTE, including 80 GW of wind farm projects. UCTE TSOs should devote a total investment of around € 17000 millions to the development of the interconnectors and their main internal transmission grid in the coming 5 years [7]. Most of this amount will be invested into high voltage overhead lines, but underground cabling is not uncommon these days. The investment costs will therefore increase dramatically.

Appendix 7 gives a brief overview of planned grid extensions within Europe, based on the expansion plans published by UCTE, Nordel and many national TSOs.

3.2 Default grid upgrades

As part of TradeWind WP3, the grid model model was extended with planned new lines and HVDC cables [1]. The list of these grid upgrades is reproduced in Table 1 and Table 2. The zones in the table are according to Table 3.

For new branches listed in Table 1 there is an assumed increase the NTC value according to the following equation [1]:

$$NTC_{new} = NTC_{old} \frac{ATC_{new}}{ATC_{old}}$$

where:

- ATC – Available Transfer Capacity (sum of branch capacities)
- NTC – Net Transfer Capacity.

Table 1. Planned new lines.

From	To	Capacity [MW]	Year	Connection
BE	FR-2	400	2008	Chooz – Jamiolle - Monceau
GR	MK	1420	2008	Bitola – Florina
CZ	AT-1	1386	2008	2d line Slavetice - Durnrhor
ES-2	FR-6	3100	2010	France - Spain: eastern reinforcement
DK	DE-2	1660	2010	Upgrading of Jutland - Germany
NO-2	SE-3	800	2011	Nea – Järpstrømmen
IT-2	SI	3100	2015	Udine – Okroglo
PT	ES-1	1500	2015	Valdigem - Douro Internacional - Aldeadavilla
PT	ES-4	3100	2015	Algarve - Andaluzia
PT	ES-1	3100	2015	Galiza – Minho
RO	RS	1420	2015	Timisoara – Varsac
IT-2	AT-2	3100	2020	Thaur – Bressanone (Brenner Basis Tunnel)
AT-1	HU	1514	2020	Wien/Südost - Gÿor
AT-2	IT-2	530	2020	Nauders – Curon / Glorenza
AT-2	IT-2	3100	2020	Lienz – Cordignano

Table 2. Planned new HVDC connections.

From	To	Name	Capacity [MW]	Year
Netherlands	Norway	NorNed	700	2009
Denmark West	Denmark East	Great Belt	600	2010
Great Britain	Ireland	East-West interc.	500	2010
Netherlands	Great Britain	BritNed	1000	2011
Sweden	Finland	Fenno scan 2	800	2015
Norway	Denmark West	Skagerrak 4	600	2020
Norway	Germany	NorGer	1400	2020

3.3 Grid model area

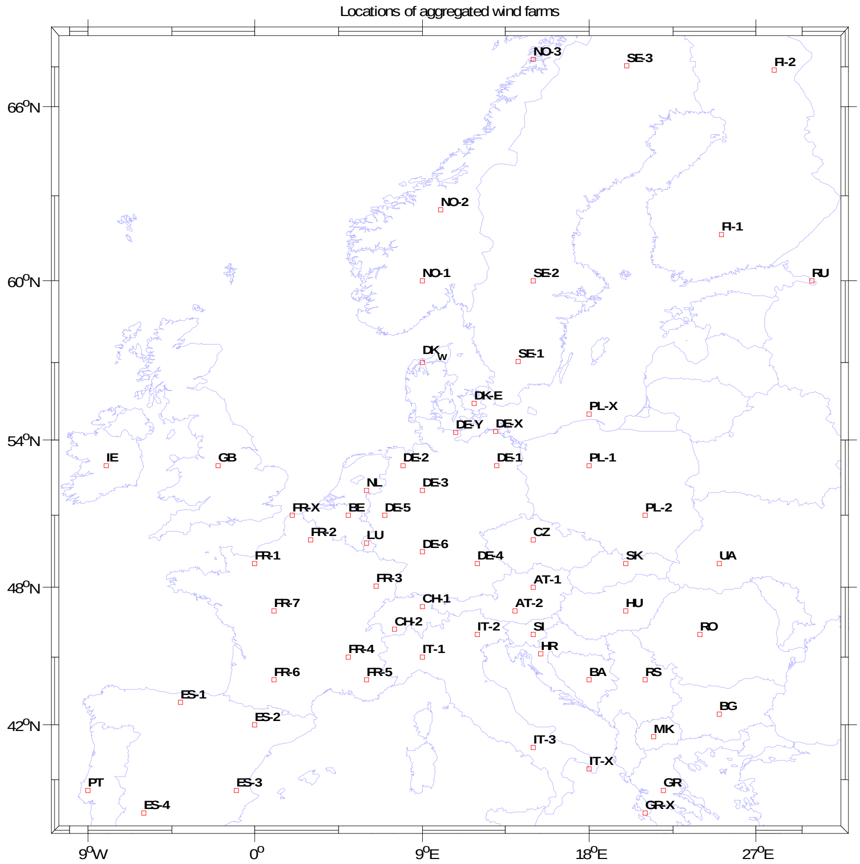

Figure 6. Geographical overview of grid zones.

Country and zone codes are given in Table 3. These grid upgrades are included in the model as default for the corresponding years, and were also included in the WP5 simulation studies [3].

Table 3. Country and zone codes used in the grid model [17].

NL	The Netherlands	FR-1	France
BE	Belgium	FR-2	France
LU	Luxemburg	FR-3	France
CZ	Czech Republic	FR-4	France
SI	Slovenia	FR-5	France
GR	Greece	FR-6	France
HU	Hungary	FR-7	France
GB	Great Britain	FR-X	France External (DC to England)
PT	Portugal	IT-1	Italy
HR	Croatia	IT-2	Italy
RS	Serbia & Montenegro	IT-3	Italy
RO	Romania	IT-X	Italy external (DC to Greece)
BG	Bulgaria	PL-1	Poland
BA	Bosnia-Herzegovina	PL-2	Poland
SK	Slovak Republic	PL-X	Poland external (DC to Sweden)
UA	Ukraine	CH-1	Switzerland
MK	Macedonia	CH-2	Switzerland
AT-1	Austria	IE	Ireland
AT-2	Austria	GR-X	Greece external (DC from Italy)
DE-1	Germany	SE-1	Sweden South
DE-2	Germany	SE-2	Sweden Middle
DE-3	Germany	SE-3	Sweden North
DE-4	Germany	FI-1	Finland South
DE-5	Germany	FI-2	Finland North
DE-6	Germany	NO-1	Norway South
DE-Y	Germany external (for DC Sweden)	NO-2	Norway Middle
DE-X	Germany external (for DC Denmark)	NO-3	Norway North
ES-1	Spain	DK	Denmark West
ES-2	Spain	DK-E	Denmark East
ES-3	Spain	RU	Russia
ES-4	Spain		

3.4 Method for selection of grid upgrades

In WP6, the need for further grid reinforcements are assessed for the simulation years 2015, 2020 and 2030, based on the Medium wind scenario. The need for further grid reinforcements is identified in two stages, where the stages are given as follows:

1. In the first stage necessary reinforcements were made to ensure that the system was capable of supplying the required demand at all load buses for all scenario years, including reference scenarios without wind power. The first stage also includes the planned upgrades.

2. In the second stage reinforcements were identified based on sensitivity of branch and HVDC capacity in an attempt to reduce the bottleneck cost caused by large scale integration of wind as well as redistribution of generation to lower cost production units in general. Branch sensitivity refers to the reduction in the objective function of the market model (in our case fuel cost savings) by increasing the branch capacity by 1 MW. Sensitivity of

power line capacity is defined and described in more detail in TradeWind deliverable D3.2 [2].

The reinforcements were mainly made as either new branch or HVDC connections parallel to the same size and type as for existing connections. In some cases where there exist documented plans or ideas of new connection, these were also included.

The stage 2 reinforcements are based on the branch and HVDC sensitivities presented in Chapter 4. For some cases the stage 2 reinforcements are the same as stage 1 in an earlier year, in which case the reinforcement is performed only once. There is only one exception to this rule, the internal connection between Diele and Conneforde in North West of Germany.

Simulations were run for years 2015, 2020 and 2030 using the TradeWind Medium wind capacity scenario as default, and using the Low and High scenarios for sensitivity studies on how increased wind development influences the flow on critical corridors. The TradeWind scenarios for wind power capacity and the allocation of capacity to different grid zones are presented in other WP deliverables [2], [3], [4]. In the original Tradewind scenarios (D2.1 Wind Power Capacity Data Collection), the scenario for offshore wind power capacity in Great Britain was set to 7.8 GW for 2030 Medium and High. After an updated assessment of offshore wind plans, it was decided, as for the grid studies in WP5, to increase the offshore wind capacity in Great Britain to 33 GW in the 2030 Medium and High scenarios.

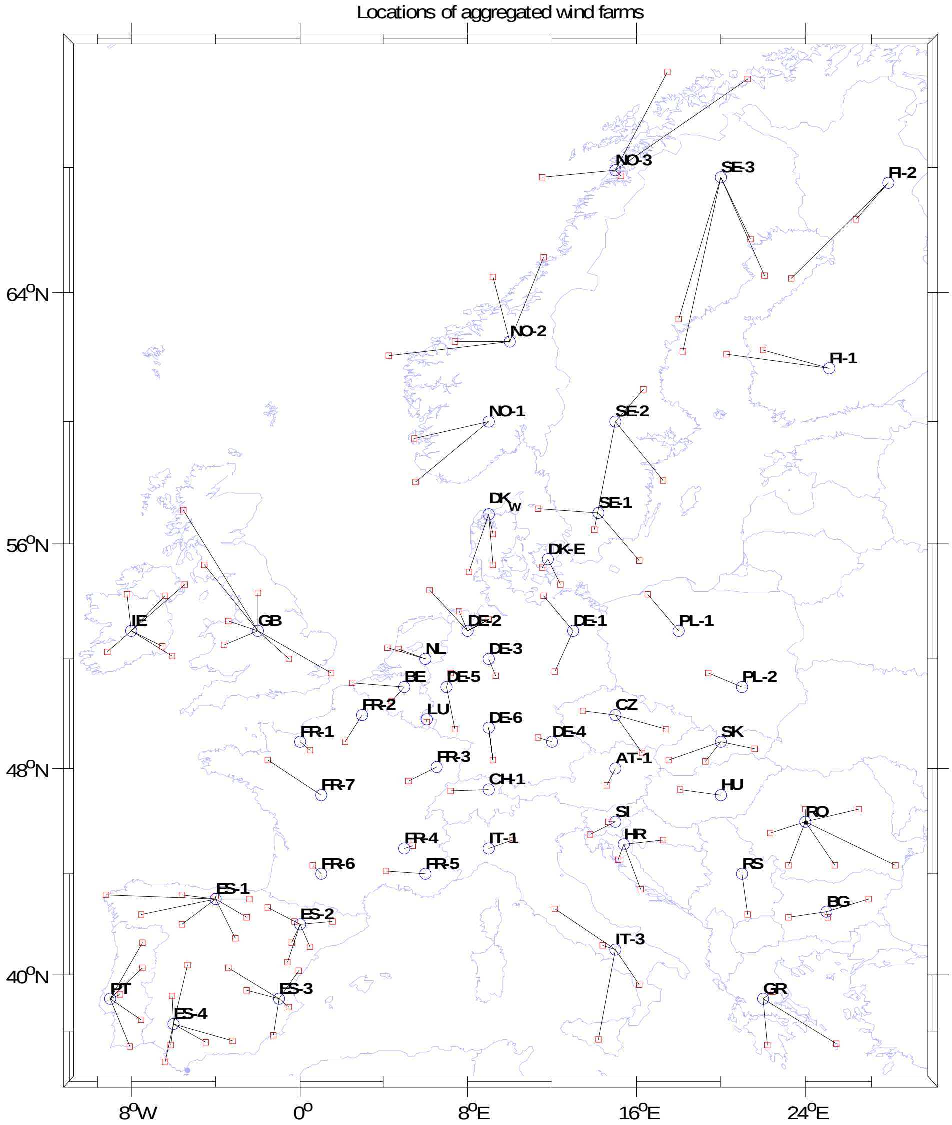

Figure 7. Locations of aggregated wind farms from [4] (Red squares) and their corresponding grid zones (shown as lines to the blue circles). The lines do not represent physical connections. See Appendix 6 for a list of connection points for the wind farms.

Table 4 and Table 5 list the installed wind generation capacities for the medium wind scenario for both offshore and onshore installations used in the simulations.

Table 4. Offshore wind capacities (MW), Medium

	2010	2015	2020	2030
DE	940	9800	20351	25000
NL	450	2000	3450	3450
BE	216	500	1251	2957
ES	0	2000	5000	9000
NO	0	130	480	2500
SE	400	1800	3799	5800
GR	205	195	260	365
GB	3324	4824	6324	33000

RO	30	200	800	1250
SF	90	550	1200	1800
DK	690	1040	1592	3000
IE	25	400	400	500
Total	6370	23439	44907	88622

Table 5. Onshore wind capacities (MW), Medium

	2010	**2015**	**2020**	**2030**
DE	24351	26203	27851	29244
NL	2500	3250	3500	3600
BE	534	786	1038	2026
LU	66	96	126	184
FR	4840	16745	30000	45000
CH	40	150	300	600
IT	5893	9130	11620	15355
AT	1160	3000	3500	4300
ES	19475	24476	29477	39479
NO	1057	2220	3180	3480
SE	1200	1800	2700	4200
CZ	580	900	1200	1500
SI	85	220	430	540
GR	1274	2549	3380	5263
HU	325	450	850	900
GB	4188	5989	9954	10312
PT	4099	5647	7211	8964
HR	400	580	1400	3000
RS	10	40	80	200
RO	315	900	1700	2050
BG	183	540	875	2160
SK	175	245	280	303
PL	1200	3500	6000	12000
SF	260	350	500	1400
DK	2939	3282	3716	4282
IE	1930	2857	4137	4498
Total	79079	115906	155006	204840

Figure 8 show installed wind capacities, both on- and offshore, for the years 2010, 2015, 2020 and 2030. The white area above each bar shows the offshore part for each scenario low, medium or high.

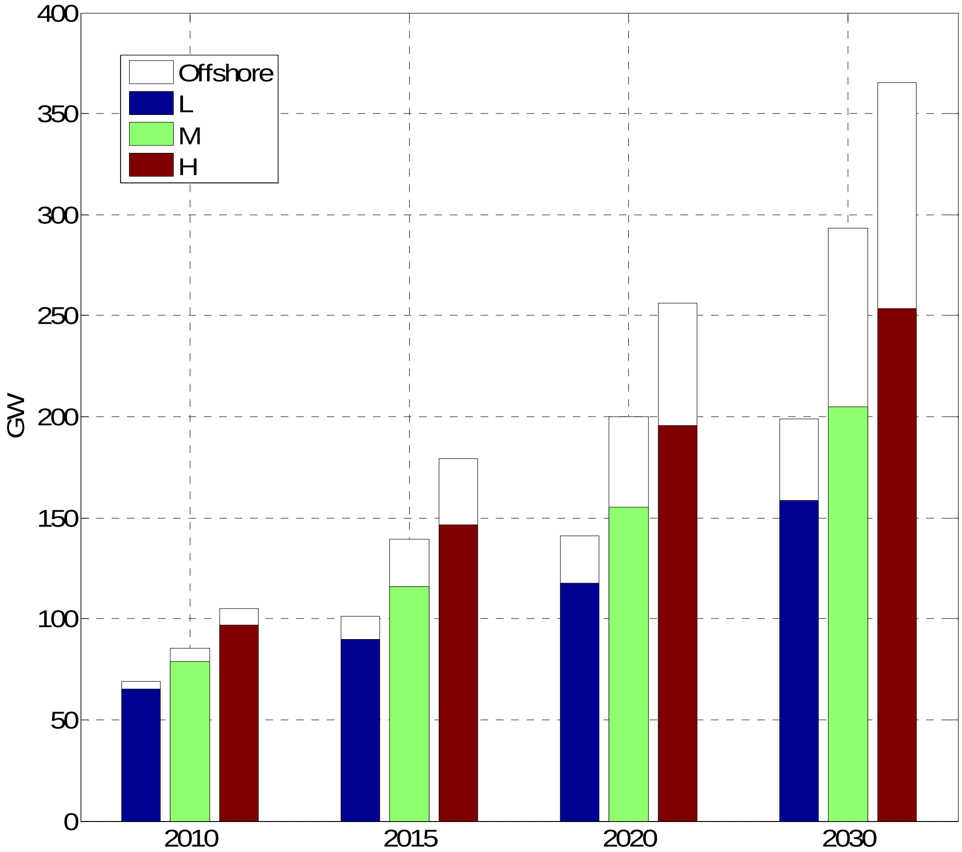

Figure 8. Total wind capacities (onshore and offshore) [GW]

The analyses are based on the developed TradeWind model of the European power system and the collected TradeWind data on load, generation and grids [1], [2]. The simulations are carried out using the Power System Simulation Tool (PSST) which solves an optimal power flow problem for a given power system model for each hour of a year [2]. The optimal power flow minimises the total generation cost, using a simplified DC power flow representation and with the assumption of a perfect market. By *perfect market* we mean that there is one European market with free competition and that no market power is being executed, i.e. we assume that the market bids equal the marginal costs of generation. Start-stop costs of thermal power plants are not explicitly included, and neither are costs related to balance management due to wind and load forecast errors.

Thermal capacities for lines between countries are included in the grid model. In addition, Net Transfer Capacities put a limit to how much power that can be transported between countries. Lines between and within grid zones are represented as physical lines [1], [13]. However, data on line capacities within grid zones, and between grid zones internally in a country were only to a limited degree available (Parts of Germany, Nordel and a few lines in Austria, France and

Belgium). See Appendix 2 for a complete list of internal grid constraints. The reader should also refer to Chapter 6 for an overview of the assumptions made, and a discussion of the limitations of the model, methodologies and data used in the studies.

3.5 Stage 1 reinforcements

For the stage 1 unplanned branch reinforcements, as shown in Table 6, the major upgrades are almost all internally in Germany. This is due to the fact that internal constraints is partly included in Germany, see Appendix 2, and that upgrades are necessary to handle load growth in 2020 and 2030. Years simulated are marked with bold year numbers.

Table 6. Stage 1 branch reinforcements including planned new connections. Internal zones reinforcements are marked with grey colour.

Year	Countries		Type	Rate [MW]	Comments
2008	BE	FR-2	AC	400	Planned: Chooz – Jamiolle - Monceau
	GR	MK		1420	Planned: Bitola – Florina
	CZ	AT-1		1386	Planned: 2d line Slavetice - Durnrhor
2009	NO	NL	HVDC	700	Planned: NorNed
2010	ES-2	FR-6	AC	3100	Planned: France - Spain: eastern reinforcement
	DK	DE-2		1660	Planned: Upgrading of Jutland - Germany
	DK	DK-E	HVDC	600	Planned: Great Belt
	GB	IE		500	Planned: East-West interc.
2011	NO-2	SE-3	AC	800	Planned: Nea – Järpstrømmen
	NL	GB	HVDC	1000	Planned: BritNed
2015	IT-2	SI	AC	3100	Planned: Udine – Okroglo
	PT	ES-1		1500	Planned: Valdigem - Douro Internacional - Aldeadavilla
	PT	ES-4		3100	Planned: Algarve - Andaluzia
	PT	ES-1		3100	Planned: Galiza – Minho
	RO	RS		1420	Planned: Timisoara – Varsac
	SE	FI	HVDC	800	Planned: Fenno scan 2
2020	IT-2	AT-2	AC	3100	Planned: Thaur – Bressanone (Brenner Basis Tunnel)
	AT-1	HU		1514	Planned: Wien/Südost - Gÿor
	AT-2	IT-2		530	Planned: Nauders – Curon / Glorenza
	AT-2	IT-2		3100	Planned: Lienz – Cordignano
	DE-1	DE-1		751	North-East upgrade done in connection with Polish grid, see [TEN-E]
	DE-1	PL-1		392	
	DE-2	DE-2		2764	Internal North-West Germany
	DE-5	DE-5		5094	Internal Midwest Germany
	NO	DK	HVDC	600	Planned: Skagerrak 4

	NO	DE		1400	Planned: NorGer
2030	NL	BE	AC	2746	Branch between the Netherlands and Belgium
	DE-1	DE-1		408	North-East upgrade done in connection with Polish grid, see [TEN-E]
	DE-3	DE-3		1659	Internal Mid-Germany
	DE-4	DE-4		2091	Internal South-East Germany
	DE-5	DE-5		1698	Internal Midwest Germany
	ES-2	FR-6		330	Branch between Spain and France
	FR-3	CH-2		320	Branch between France and Switzerland
	NL	NO-1	HVDC	700	HVDC between the Netherlands and Norway
	GB	IE		1000	HVDC between Great Britain and Ireland
	GB	FR-X		2000	HVDC between Great Britain and France

Further recommendations for grid upgrades within countries will require a detailed study, which is not within the scope of this project. The focus in this project has been on interconnections, though the constrained connections internally in Germany have been improved in order to find a reasonable solution. It has been considered important to include internal constraints for Germany in the grid model, due to the high amounts of wind power that are expected to be installed in critical areas, especially in the North Western parts of the country.

3.6 Stage 2 reinforcements

As explained above, the stage 2 reinforcements are based on branch and HVDC-link sensitivities. In TradeWind WP5, the branch, HVDC and NTC sensitivities were used to identify grid bottlenecks for all TradeWind scenarios, by simulating the existing grid including the default reinforcements listed in

Table 2 and Table 1. The selection of added reinforcements is given in Table 7, and is based on the assessment of grid bottlenecks in Chapter 4.

Table 7. Stage 2 branch reinforcements. Internal zones reinforcements are marked with grey colour.

Year	Countries		Type	Rate [MW]	Comments
2015	ES-2	FR-6	AC	330	Upgrade between Spain and France
	FR-3	CH-2		320	Upgrade between France and Switzerland
	NL	NO-1	HVDC	700	Upgrade of NorNed between Norway and the Netherlands
	DK-E	DE-X		550	Upgrade between Denmark and Germany
	GB	FR-X		2000	Upgrade between Great Britain and France
	NO-1	DK		350	Upgrade between Norway and Denmark
	DK	SE-2		360	Upgrade between Denmark and Sweden
	DE-X	SE-1		600	Upgrade between Germany and Sweden
	IT-X	GR-X		500	Upgrade between Italy and Greece
	PL-X	SE-1		600	Upgrade between Poland and Sweden
2020	NL	BE	AC	1476	Upgrade between The Netherlands and Belgium
	NO-1	NO-1		1000	Internal upgrade in South Norway
	DE-1	DE-1		1659	Internal upgrade in North-East Germany
	DE-2	DE-2		1695	Internal upgrade in North-West Germany
	DE-4	DE-4		301	Internal upgrade in South-East Germany
	DE-6	CH-1		1131	Upgrade between Germany and Switzerland
	FR-1	FR-1		1000	Internal upgrade in northern parts of France
	FR-4	IT-1		956	Upgrade between France and Italy
	IT-1	CH-2		1510	Upgrade between Italy and Switzerland
	DK-E	DK	HVDC	600	Internal upgrade between Denmark East and West
	NO-1	NO-2		1000	Internal upgrade between South and Mid-Norway.
	IT-X	GR-X		500	Upgrade between Italy and Greece
2030	NO-1	NO-1	AC	1000	Internal upgrade in South Norway
	AT-1	DE-4		602	Upgrade between Austria and Germany
	DE-1	DE-1		1659	Internal upgrade in North-East Germany
	DE-2	DE-2		3077	Internal upgrade in North-West Germany
	DE-2	DE-3		1369	Internal upgrade between North-West and Mid-Germany
	DE-6	CH-1		1158	Upgrade between Germany and Switzerland
	FR-3	CH-2		640	Upgrade between France and Switzerland
	IT-1	CH-2		514	Upgrade between Italy and Switzerland
	GB	NO-1	HVDC	2000	New HVDC between Great Britain and Norway
	HR	IT-2		1000	New HVDC between Croatia and Italy
	FR-4	IT-1		1000	New HVDC between France and Italy

The HVDC connections are very powerful as a means to control the power flow, and upgrades will generally lead to large reduction in congestion costs. Although modelled as HVDC, power flow control could also be obtained by phase-shift technologies, see Chapter 2. The same connections appear for all years in the sensitivity list, even when they are upgraded in previous simulation year. Except for the HVDC connection between Italy (IT-X) and Greece (GR-X), connections are not upgraded a second time in 2020 when they are already upgraded in 2015.

3.7 Total reinforcements

The proposed reinforcements for all years, as a result of both stage 1 and stage 2 upgrades, are shown in Figure 9 and Figure 10. See Appendix 1 for details on size of new connections. The red lines shows HVDC connections, the blue lines show branches (AC overhead lines) and the squares are internal reinforcements within a zone.

The reinforcements are mainly new branch or HVDC connections parallel to *the same size and type* as for existing connections. Thus, the main focus has been on identifying which connections that should be considered for upgrading, rather than suggesting *optimized ratings* of new connections.

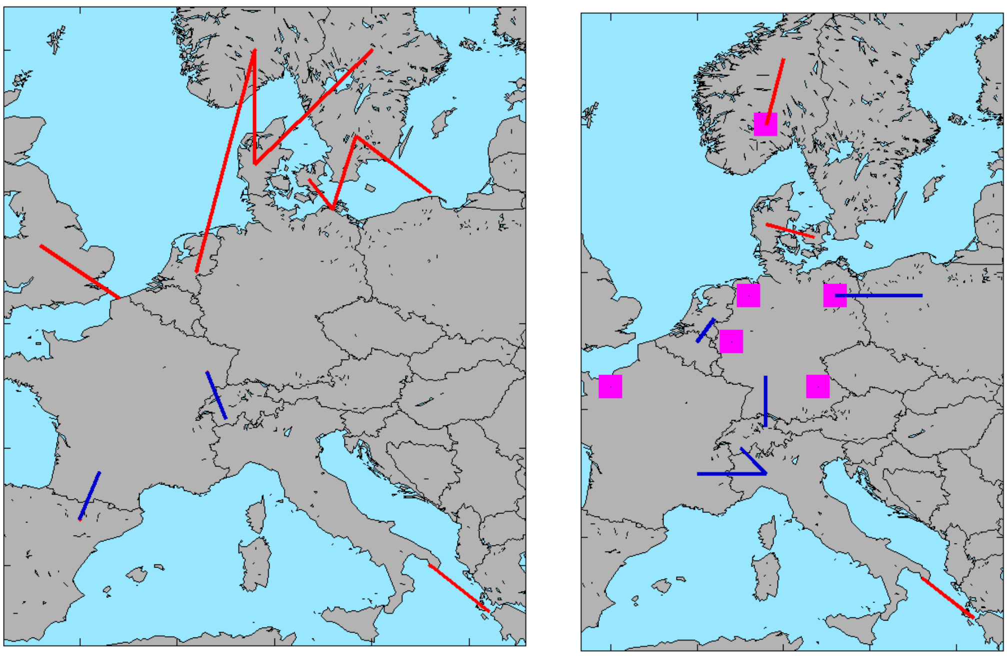

Figure 9. Grid upgrades for 2015 and 2020 based on simulation results. Default grid upgrades, given in

Table 2 and Table 1 are not shown. Blue: AC lines, Red: HVDC, Purple: Internal upgrades.

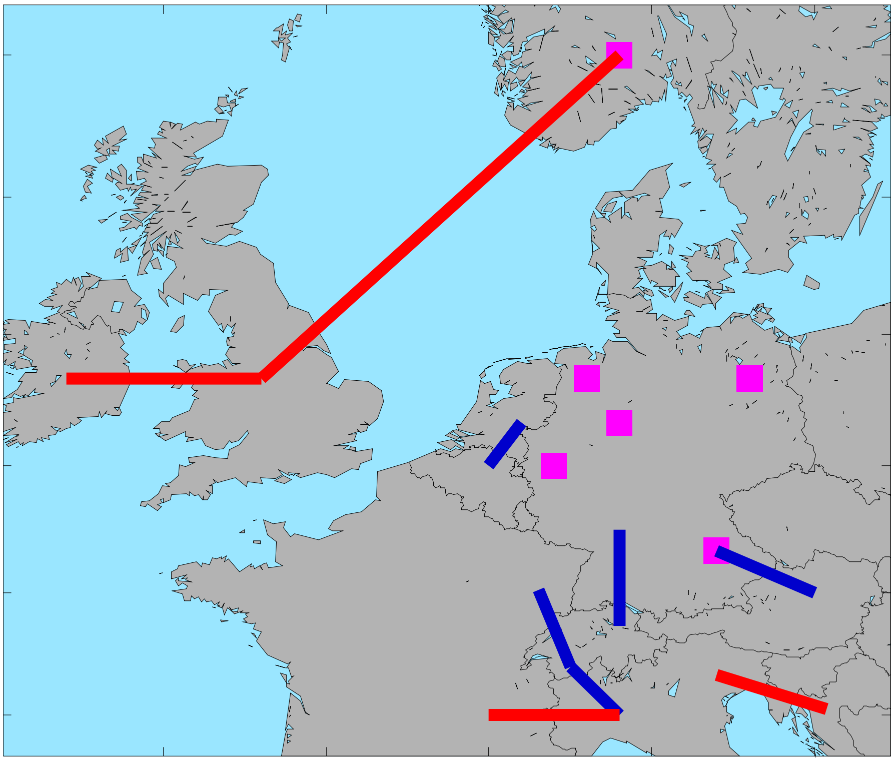

Figure 10. Grid upgrades for 2030 based on simulation results. Blue: AC lines, Red: HVDC, Purple: Internal upgrades.

4 BOTTLENECK COSTS

In this chapter, expected bottlenecks and corresponding bottleneck costs in the European network are identified based on results from the simulation model. The years studied are 2010, 2015, 2020 and 2030, where stage 1 and stage 2 grid upgrades (see Chapter 3) are made for all years greater than 2010.

4.1 Bottleneck cost calculation method

Bottlenecks (or grid congestions) arise as the market demand for power transfer exceeds the available transmission capacity. Congested transmission corridors represent an additional cost to the power market as generation has to be transferred from the cheapest available units to more expensive units to avoid overloads on lines. These additional operating costs are in this study termed "bottleneck costs".

The bottleneck cost of wind power, as shown Table 8, is estimated in the following manner:

- A simulation of the full European grid, including the Medium scenario for wind power capacity, is run for a full year (8760 hours), and the annual generation cost is divided by the total annual energy consumption (load) to get the average European generation cost in €/MWh. This system is denoted "A" in Table 8.
- Then the same simulation is performed using a copperplate model (i.e. all grid constraints removed). The difference in average generation cost between the full grid model and the copperplate model is the bottleneck cost of system A (including wind).
- We now remove all wind power from the system and run the same simulations again to calculate the bottleneck cost of system B (excluding wind)
- The difference in bottleneck cost between A and B is the wind power contribution to the bottleneck cost. Note that this value can be both positive (wind power increases bottleneck cost) and negative (wind power reduced bottleneck cost).

It is emphasized that the bottleneck costs computed here is purely an indication of the changes in the variable operating costs (marginal costs) due to wind power and network constraints, and that this has nothing to do with "congestion rents" or other possible incomes to transmission grid owners due to congestions. It is also important to note that the impact of generator start-up costs on the marginal costs is largely neglected, and that additional costs for balancing power due to uncertainty in wind power forecasts are not analysed.

Table 8. Bottleneck cost

Simulations with wind power:		
Grid model cost [€/MWh]		$Cost_{grid}$
Copperplate model cost [€/MWh]	-	$Cost_{copperplate}$
Bottleneck cost [€/MWh]	=	A
Simulations without wind power:		
Grid model cost [€/MWh]		$Cost_{grid}$
Copperplate model cost [€/MWh]	-	$Cost_{copperplate}$
Bottleneck cost [€/MWh]	=	B
Δ bottleneck cost [€/MWh]		(A-B)
Δ bottleneck cost [€/MWh wind]		$(A\text{-}B) \cdot E_{demand}/E_{wind}$

4.2 Annual energy flow in 2010

Figure 11 shows the average power flow over all 8760 hours in 2010 between the zones in the model. The width of the arrows indicates the amount of energy flowing, while the red color indicates whether or not it is a constrained connection at some time step in the simulation. The pink squares and green circles are surplus and deficit areas respectively, where the size indicates the relative level of exchange. Deficit areas might have local production to cover the total local demand, but the model finds it better for the total solution to import from a cheaper production sources elsewhere (As described in TradeWind WP3, the model minimizes the total generating costs for each hour of the year).

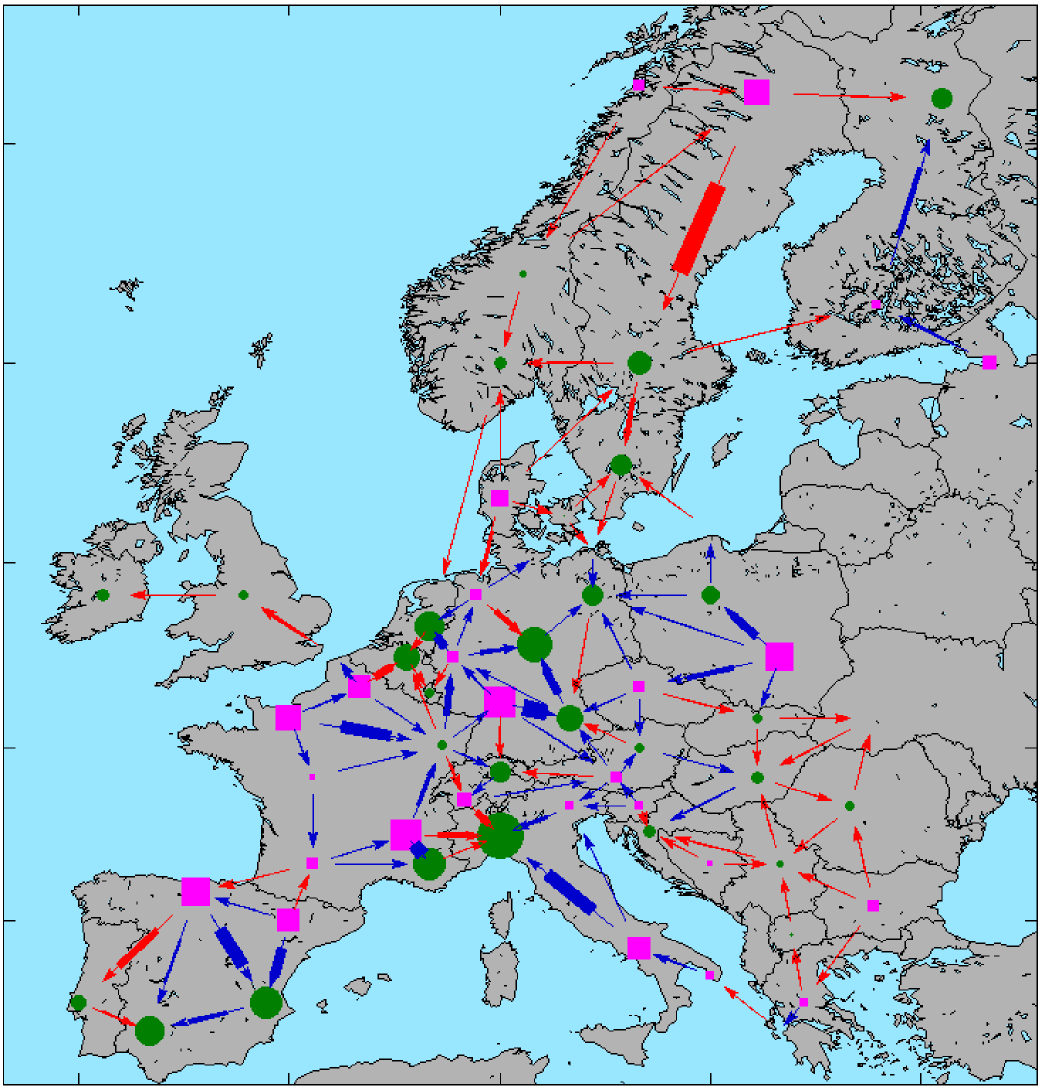

Figure 11. Annual energy flow between zones in 2010. Red: Constrained flow due to line / HVDC capacities. Blue: Non-constrained flow. Green: Energy Deficit. Purple: Energy surplus.

The figure shows the total energy flowing between countries and zones with all the directional hourly branch flows added together. From the figure it is clear that the Benelux countries are large deficit areas that have constrained power flow on several interconnections. Although the connections from Germany zone DE-2 (North West) to Netherlands and Germany zone DE-3 (below DE-2) are marked as unconstrained, the *total flow* from Germany (DE-2+DE-3) to Netherlands are constrained due to the NTC values.

The large deficit area in northern parts of Italy is supplied mainly from a constrained branch towards France, as well as from southern parts of Italy, on a connection that more than likely is carrying too much power as there are no internal constraints for Italy in the model. Also the flow towards Portugal and south-east Spain is constrained in 2010.

For supplementary discussions on energy flows and congestions for the 2010 simulations and other years for the case with no grid upgrades, the reader should refer to the TradeWind WP5 report [3].

The bottleneck cost, calculated as described in Section 4.1, is shown in Table 9 for the year 2010. The table shows that adding wind into the current system will reduce the total bottleneck cost, as Δbottleneck cost is negative.

Table 9. Bottleneck cost in 2010

Simulations with wind power:	
Grid model cost [€/MWh]	32.33
Copperplate model cost [€/MWh]	32.00
Bottleneck cost [€/MWh]	0.32
Simulations without wind power:	
Grid model cost [€/MWh]	34.85
Copperplate model cost [€/MWh]	34.48
Bottleneck cost [€/MWh]	0.37
Δ bottleneck cost [€/MWh]	-0.05
Δ bottleneck cost [€/MWh wind]	-0.98

4.3 Annual energy flow and grid upgrades for 2015

The situation for 2015, regarding relative energy flow and constraints as shown in Figure 12, is similar to that seen in 2010 with the same flow, deficit/surplus areas and constrictions. The thickness of both the circles, squares and lines are related to the largest value in the current simulation, thus the size of elements in the map can not be compared for two different simulations, only the location and direction.

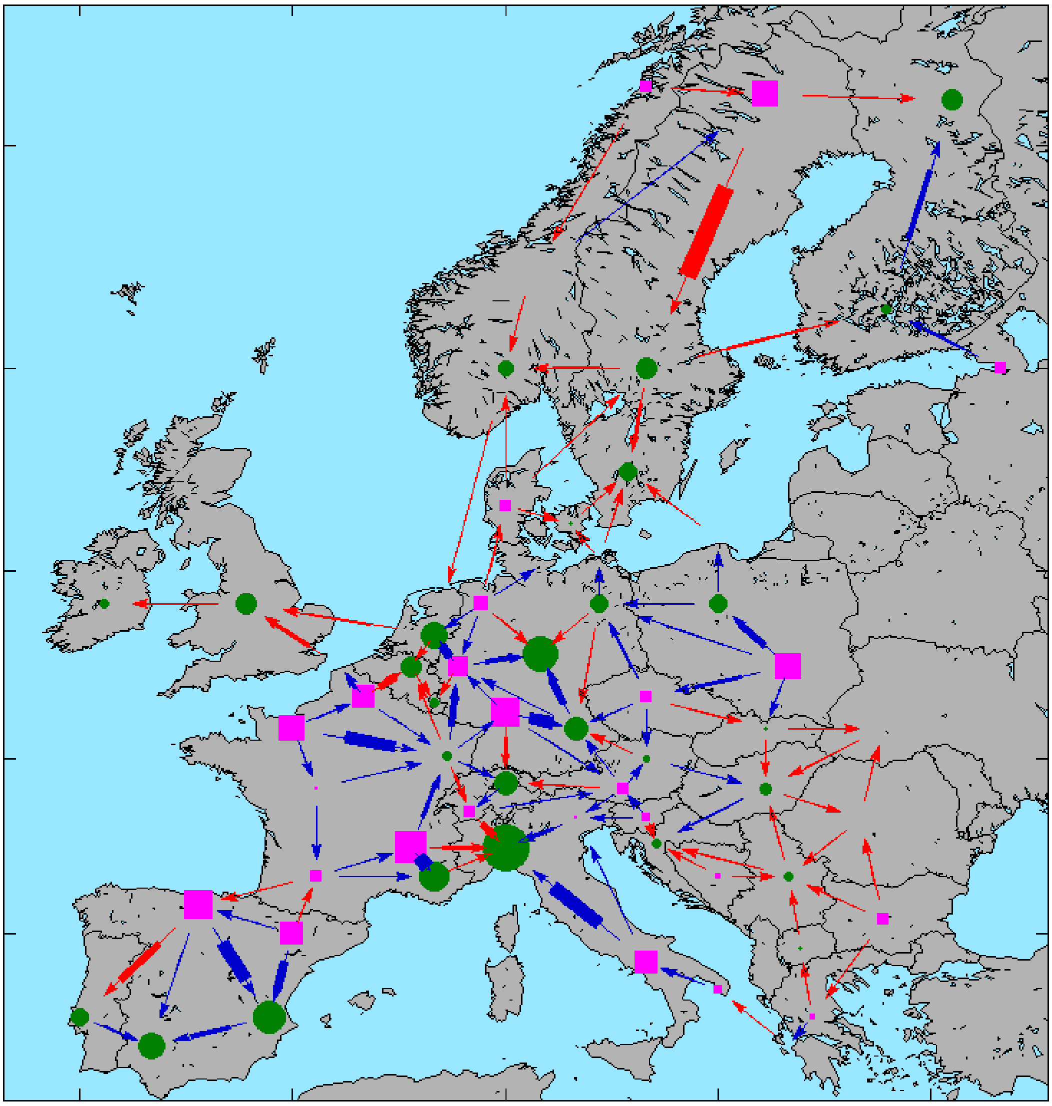

Figure 12. Annual energy flow between zones in 2015. Red: Constrained flow due to line / HVDC / NTC capacities. Blue: Non-constrained flow[1]. Green: Energy Deficit. Purple: Energy surplus.

All stage 2 new branch and HVDC connections for 2015 are taken from the list of connections with greatest sensitivities as shown Figure 13, see also Appendix 1.

[1] Although the connections from Germany zone DE-2 (North West) to Netherlands and Germany zone D3 (below DE-2) are marked as unconstrained, the total flow from Germany (DE-2+D3) to Netherlands are constrained due to the NTC values.

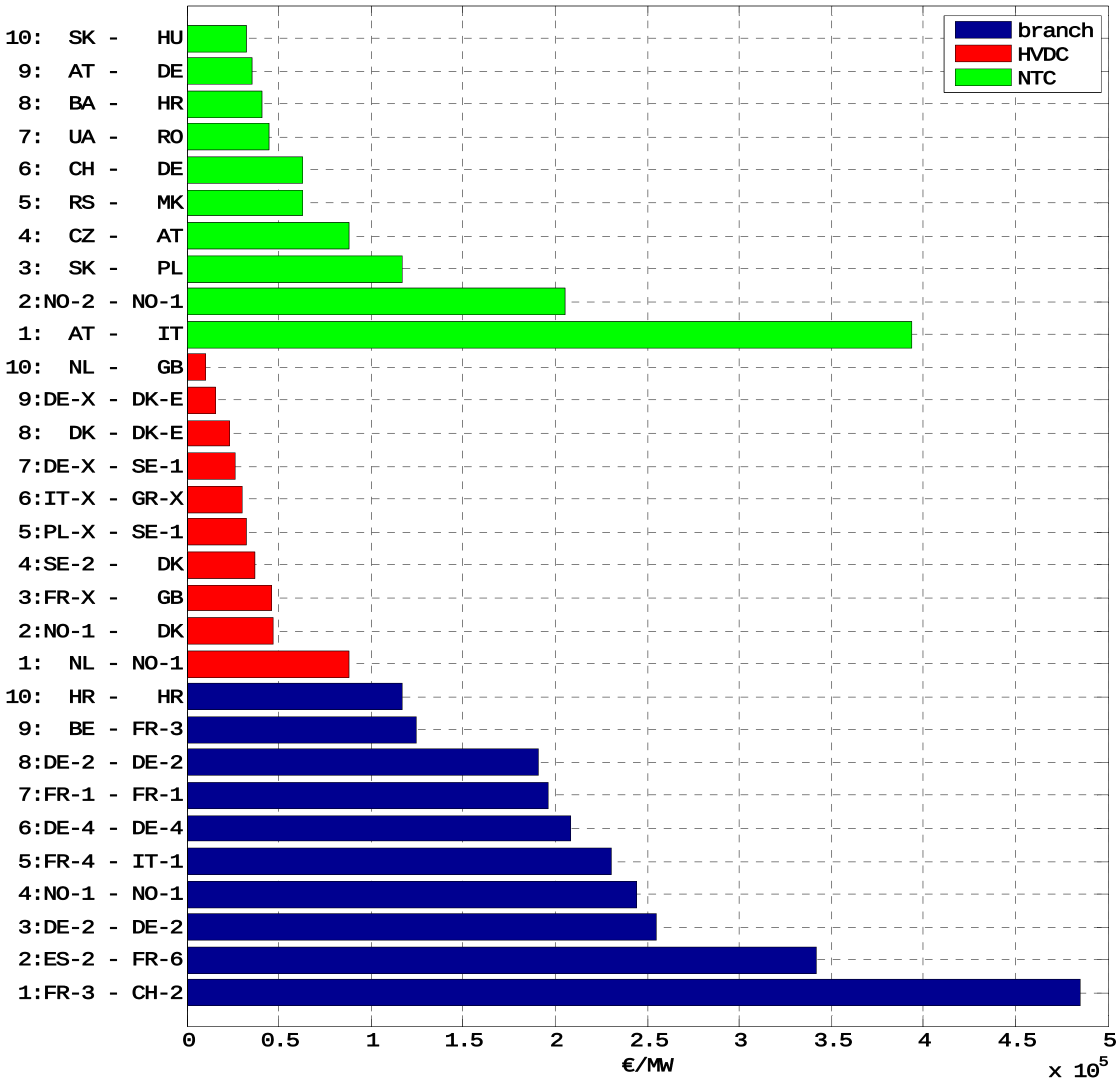

Figure 13. The 10 largest sensitivities on constraints (2015)

To make a choice on which of the connections that should be prioritised for upgrading, not only the sensitivity value but also the costs of building new lines should be taken into account. Costs for new lines are very difficult to predict, since the total costs depends on many factors such as land topography and population density. By assuming constant specific line costs (€ / MW km), a more correct ranking of grid upgrades could have been made by multiplying the sensitivity values by the line length. However, line lengths are not easily estimated from the reduced DC power flow model. This is therefore not part of this study.

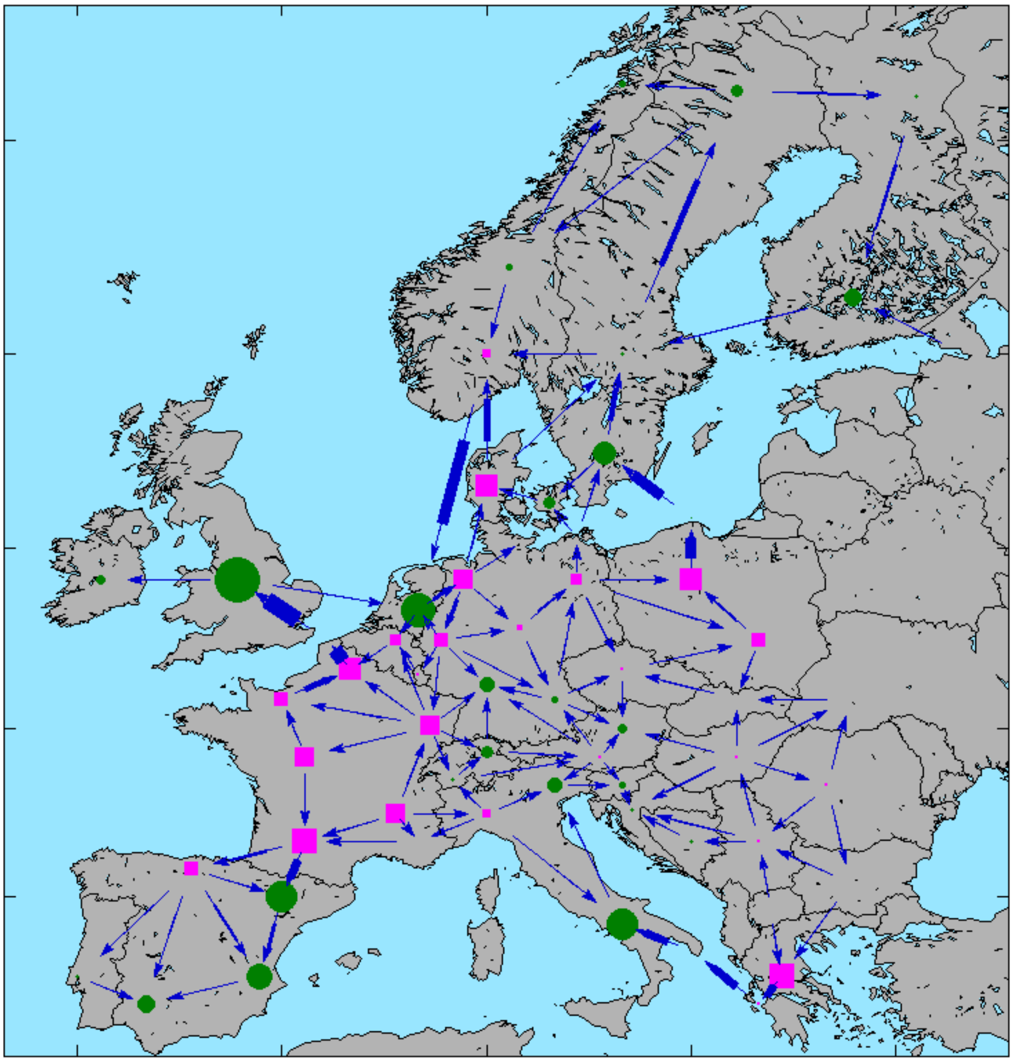

Figure 14. Change in energy flow in 2015 due to stage 2 reinforcements. Green: Reduction in production. Purple: Increase in production.

The change in energy flow and production after adding the stage 2 reinforcements for 2015 is shown in Figure 14. The green circles indicate that there is a reduction in production, as it is possible to produce at lower price elsewhere due to the increased capacity, while the pink squares indicates an increase in production.

Both Ireland and Great Britain will reduce their production, due to increased HVDC capacity towards the main of Europe. Otherwise it is the southern parts of Spain and Italy as well as Netherlands which will decrease the total production, while France and Poland have a large increase. There seem to be an increase in the flow going from Poland through Scandinavia and down through the enforced NorNed connection towards Netherlands.

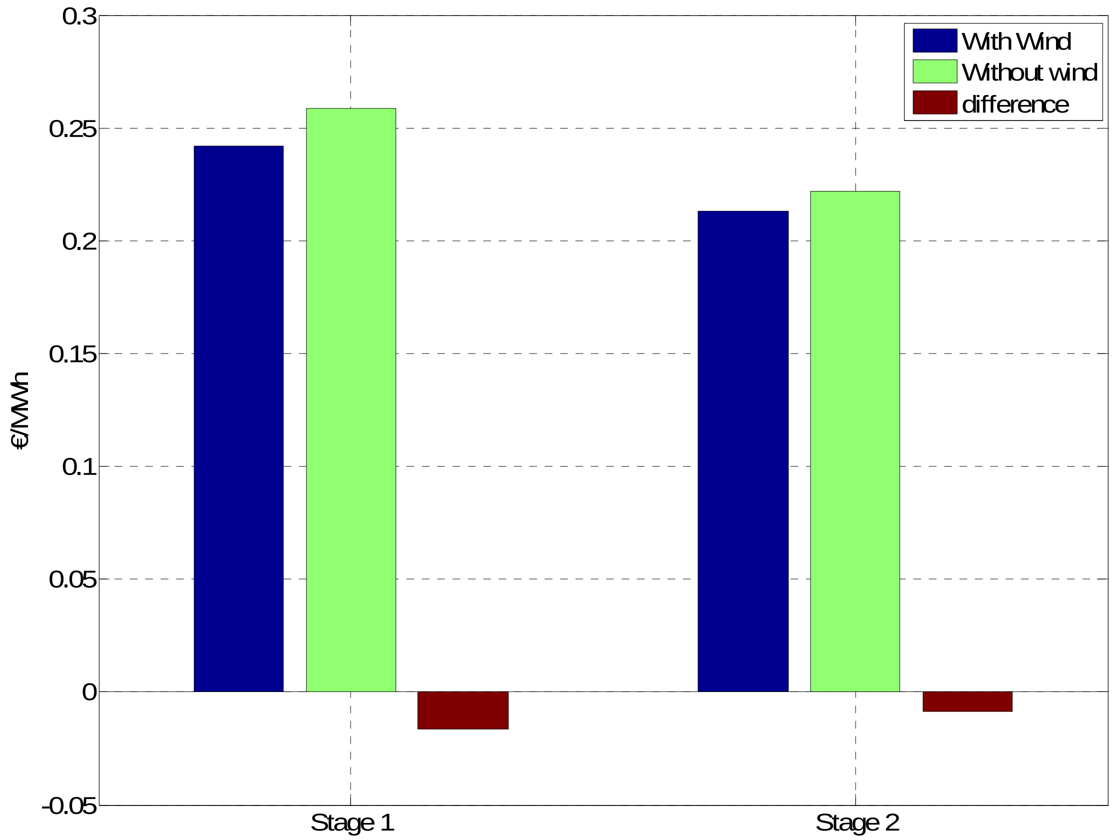

Figure 15. Bottleneck cost in 2015 with and without wind

Comparing the bottleneck costs for stage 1 and 2 grid reinforcements in 2015 shown in Figure 15, there is a reduction in bottleneck cost for both with and without wind going from stage 1 to stage 2, though the reduction is greater for the no wind scenario.

4.4 Annual energy flow and grid upgrades for 2020

The relative flow pattern for 2020 has not changed much from the 2015 scenario, though there is an increased surplus area in the Czech Republic and North West of Germany. The number of constrained zonal connections is reduced, see Figure 16.

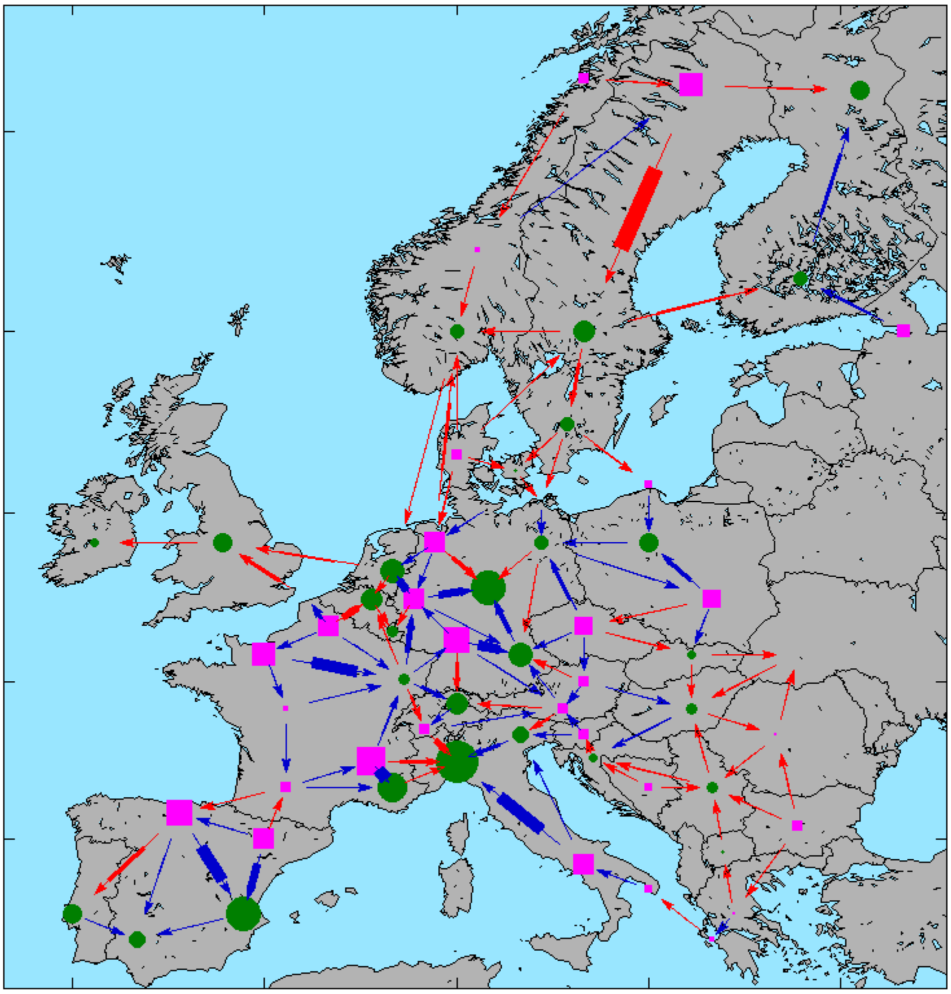

Figure 16. Annual energy flow between zones in 2020. Red: Constrained flow due to line / HVDC / NTC capacities. Blue: Non-constrained flow[2]. Green: Energy Deficit. Purple: Energy surplus.

[2] Although the connections from Germany zone DE-2 (North West) to Netherlands and Germany zone DE-3 (below DE-2) are marked as unconstrained, the total flow from Germany (DE-2+DE-3) to Netherlands are constrained due to the NTC values.

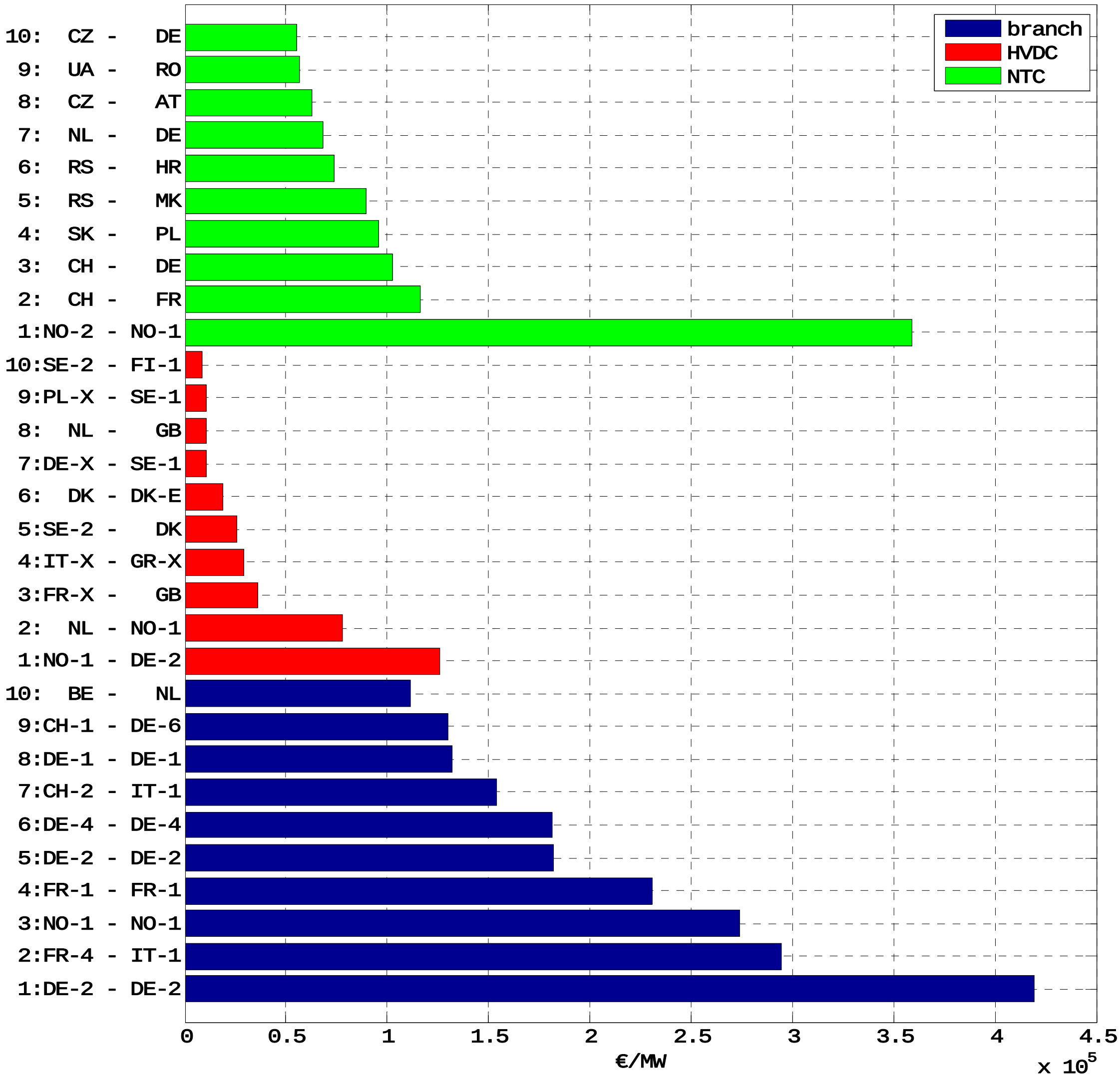

Figure 17. Sensitivities on constraints (2020)

Figure 18 shows the main critical corridors based on the sensitivities of connections. The connections with the ten highest sensitivities for each type of branch, HVDC and NTC constraints are shown in the figure. A red line indicates that one or more branches on this corridor are constrained, while NTC constrained connections are shown by dashed lines. The two types can be combined, such as the connection between Netherlands and Belgium, which is constrained by both branch and NTC limits. The yellow circles in are constrained connections within a zone. The level of the constraint is indicated by the size of the element, line, dashed line or circle.

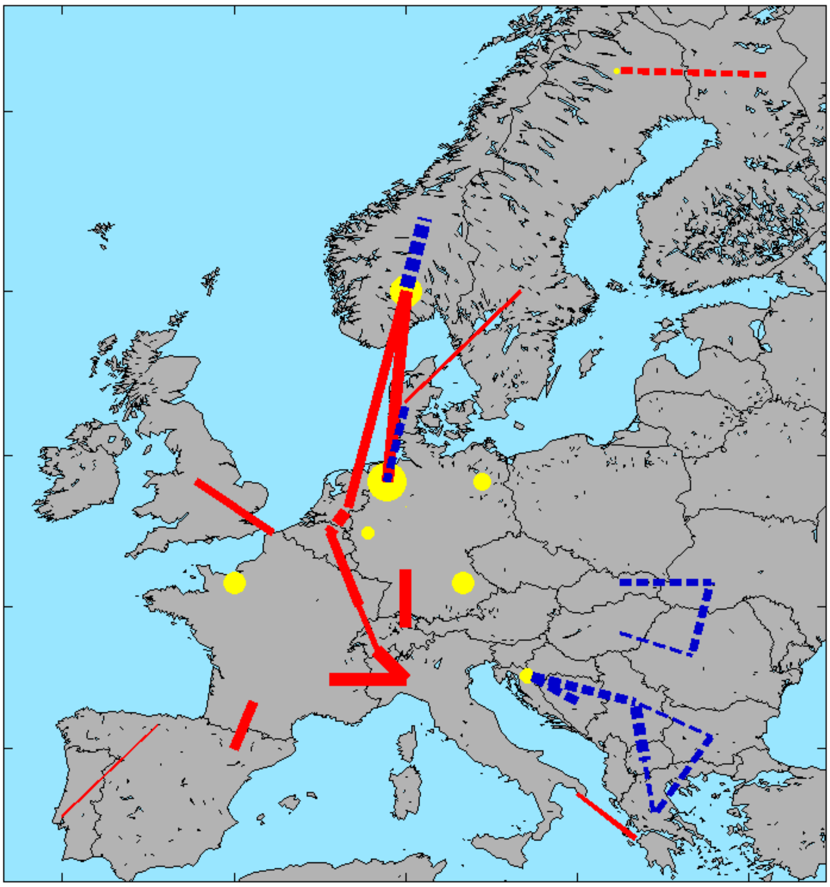

Figure 18. Critical zonal corridors based on sensitivities 2020. Red: Lines or HVDC constraints. Dashed: NTC constraints. Yellow: Internal constraints.

The change in energy flow and production due to stage 2 reinforcements in 2020 is shown in Figure 19. The production increase in Norway and West-Denmark is transported down the NorNed HVDC connection towards Netherlands, Belgium and UK. Increased production in the North of Germany replaces production in South Germany, Poland and The Czech Republic. There is an increase in production in almost all of France, exported to Spain, UK and Italy. For both southern Spain and the whole of Italy there is a decrease in production.

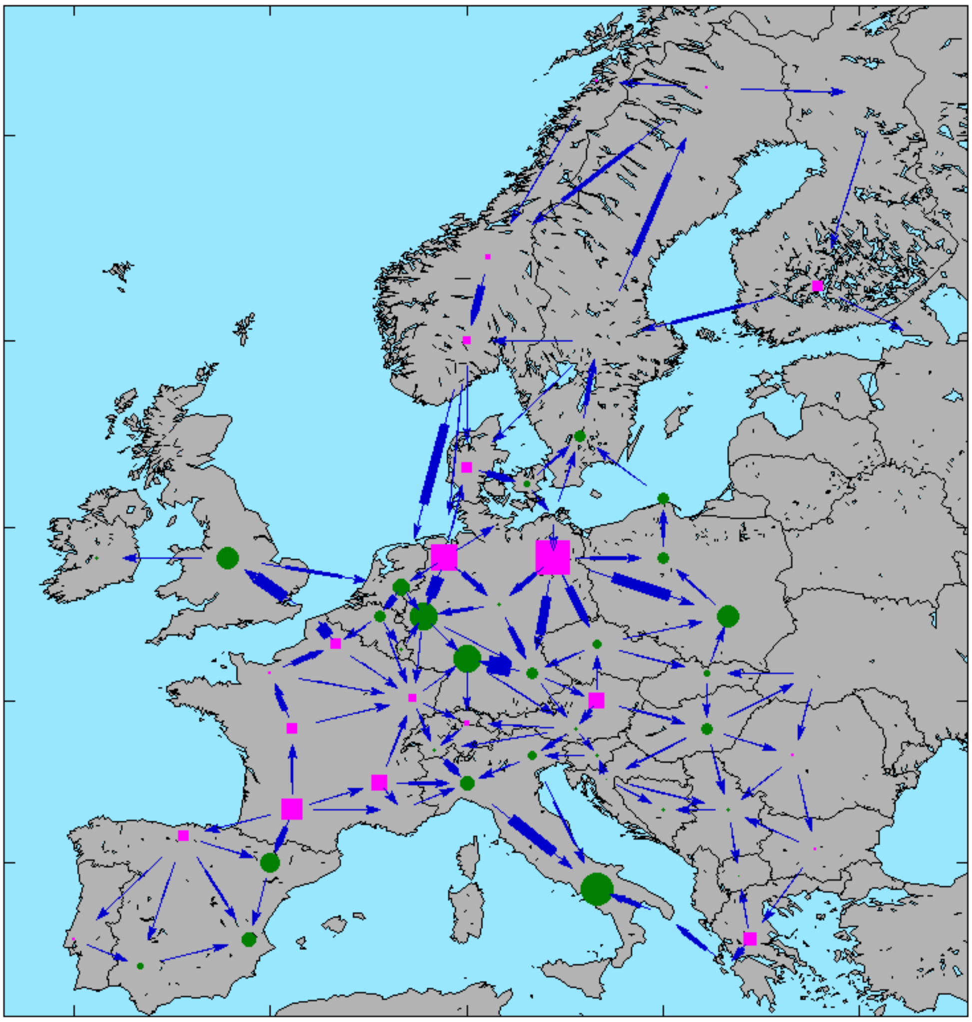

Figure 19. Change in energy flow in 2020 due to stage 2 reinforcements. Green: Reduction in production. Purple: Increase in production.

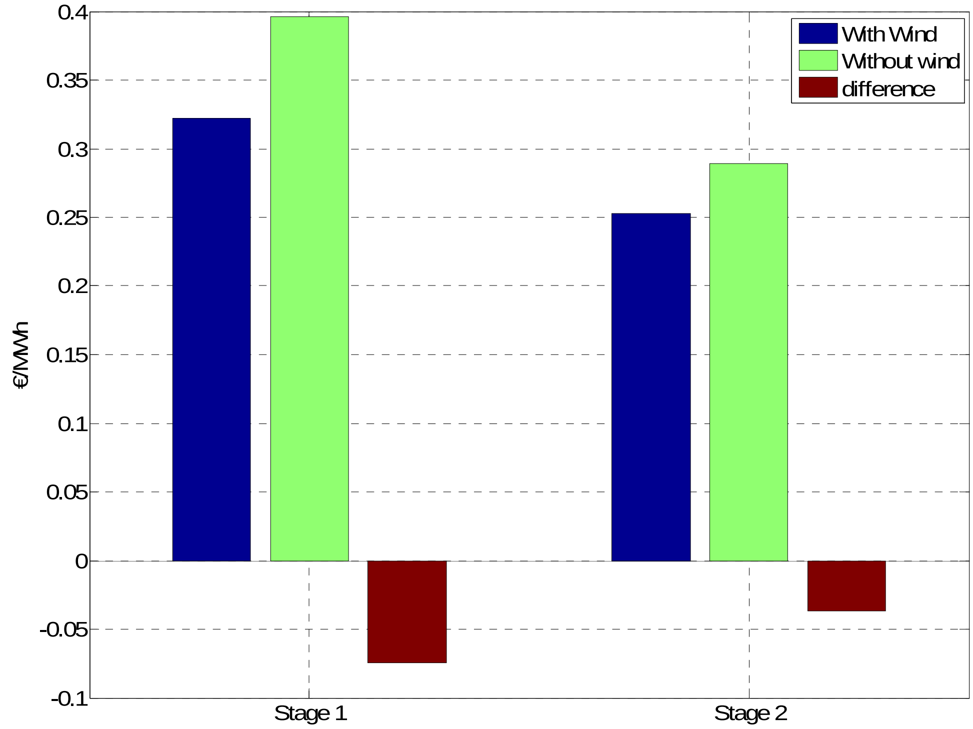

Figure 20. Bottleneck cost in 2020 with and without wind

There is a quite significant reduction in bottleneck cost due to the stage 2 reinforcements in 2020, as seen from Figure 20.

4.5 Annual energy flow and grid upgrades for 2030

The main changes in the energy flow in 2030 from the previous simulation year, 2020, is that two zones, UK and DE-1 (North East Germany), changes from deficit to surplus areas. There are some changes in direction of energy flow on a few connections, though only on connections with relatively low amounts of electricity exchange.

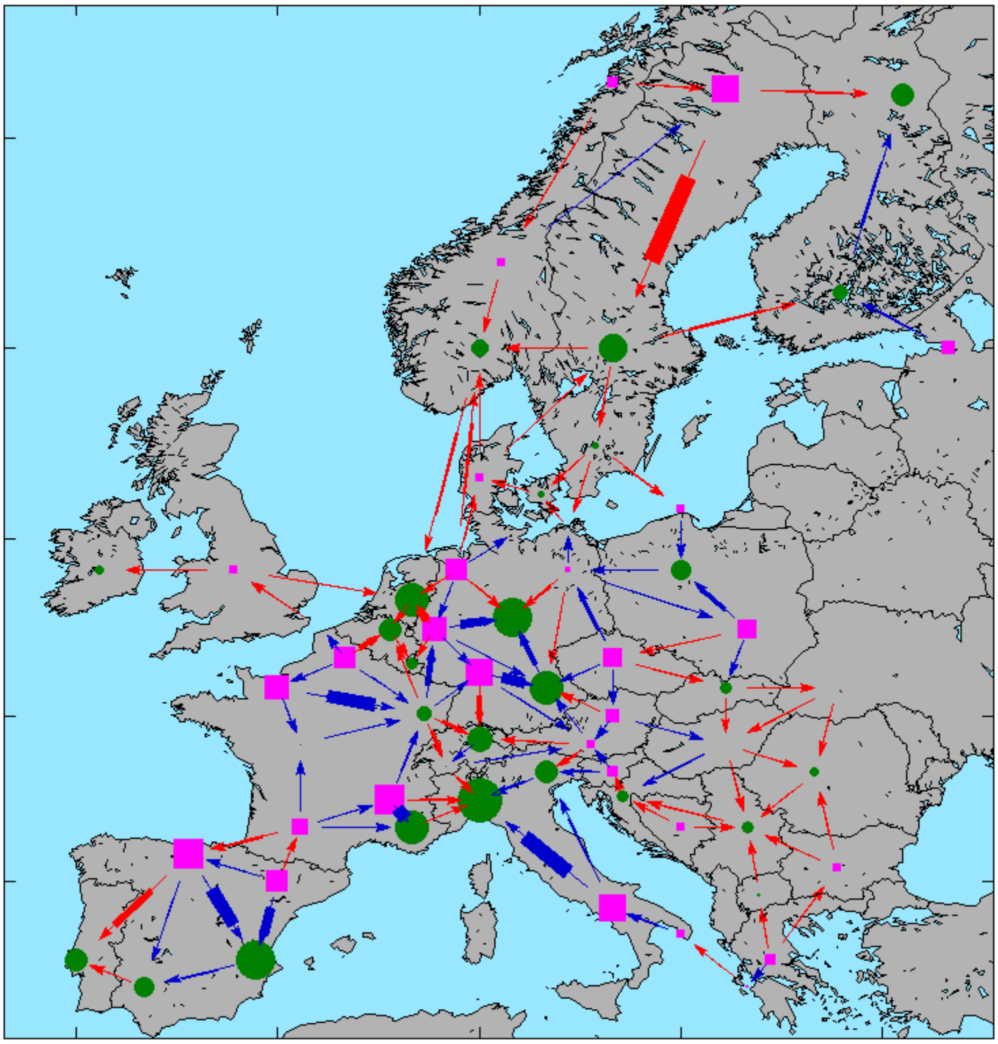

Figure 21. Annual energy flow between zones in 2030. Red: Constrained flow due to line / HVDC / NTC capacities. Blue: Non-constrained flow[3]. Green: Energy Deficit. Purple: Energy surplus.

[3] Although the connections from Germany zone DE-2 (North West) to Netherlands and Germany zone DE-3 (below DE-2) are marked as unconstrained, the total flow from Germany (DE-2+DE-3) to Netherlands are constrained due to the NTC values.

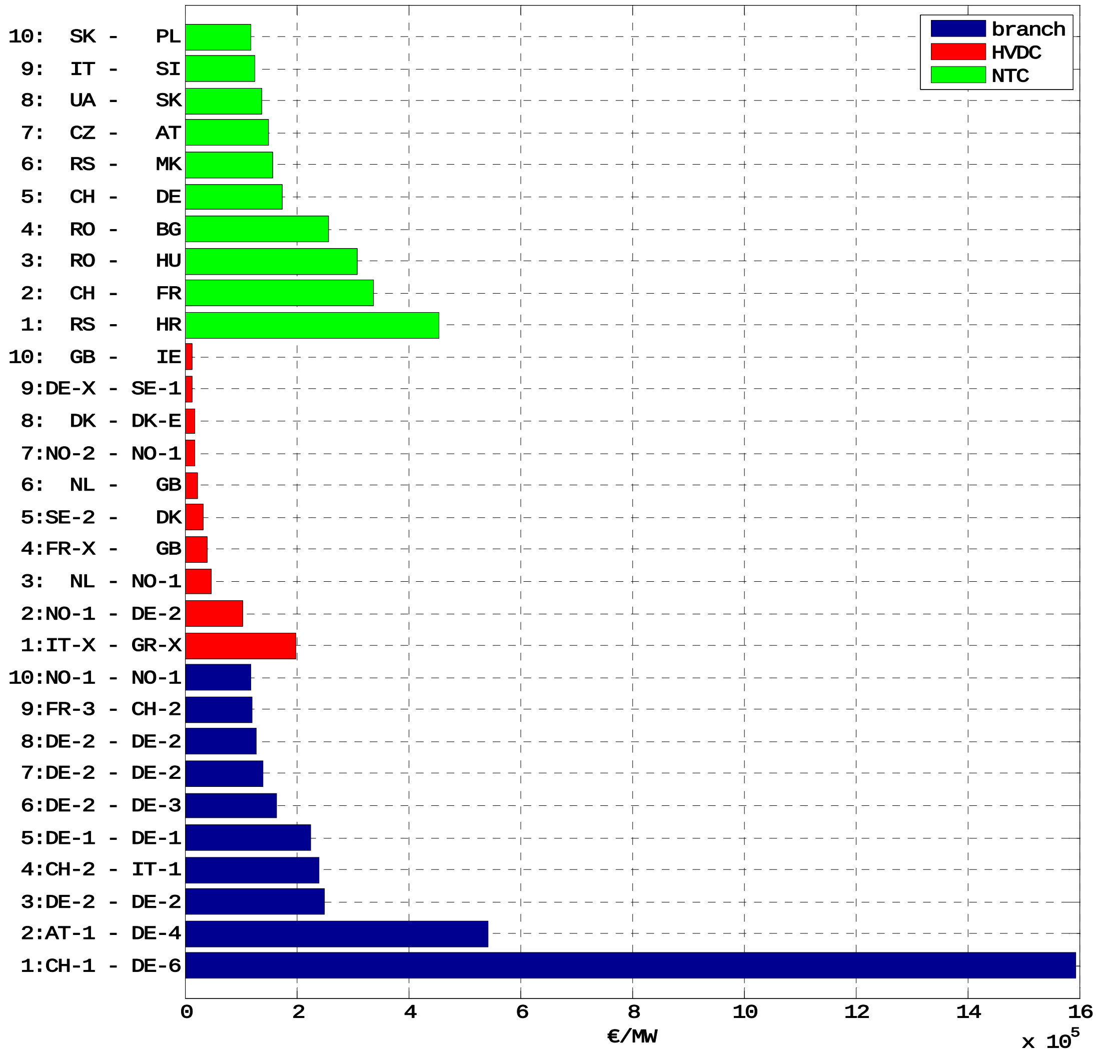

Figure 22. Sensitivities on constraints (2030)

The connection with largest sensitivity on constraint for 2030, shown in Figure 22, is between Germany ('DE-6') and Switzerland ('CH-1'). Due to the NTC constraint on the same corridor an upgrade of this connection does no give a large change in energy flow, as can be seen from Figure 24.

The main critical zonal corridors for 2020 and 2030, shown in Figure 18 and Figure 23 respectively, are with a few exceptions the same. Some of the constrained lines in 2020 are replaced by NTC constraints, mainly in Eastern Europe.

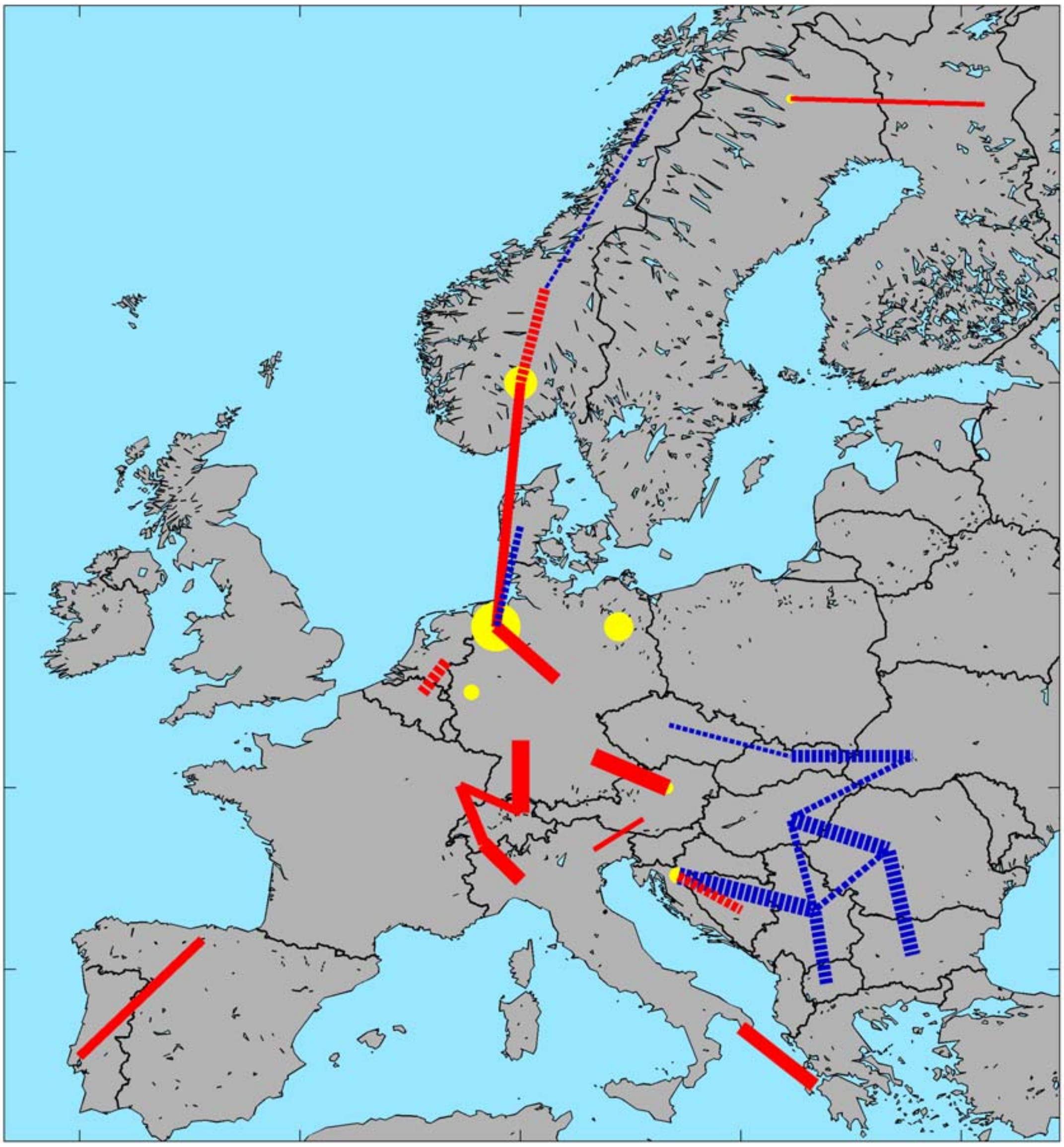

Figure 23. Critical zonal corridors based on sensitivities 2030. Red: Lines or HVDC constraints. Dashed: NTC constraints. Yellow: Internal constraints.

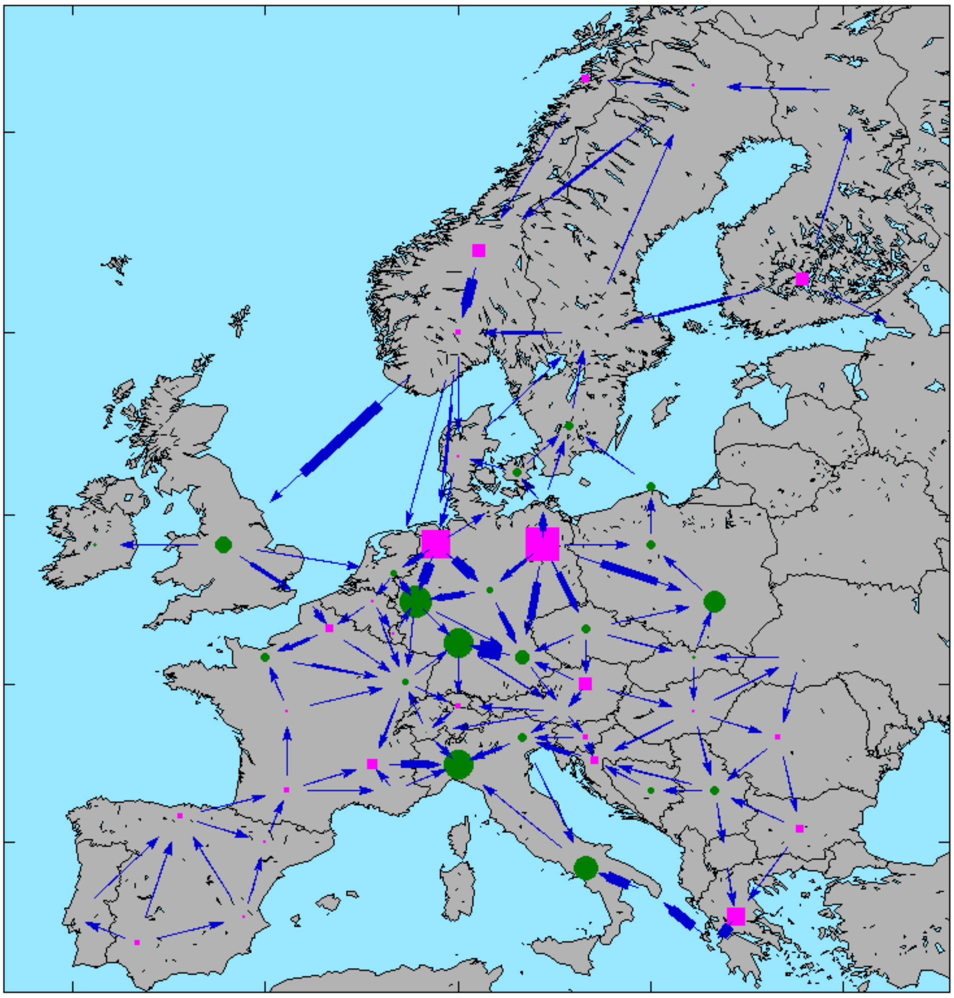

Figure 24. Change in energy flow in 2030 due to stage 2 reinforcements. Green: Reduction in production. Purple: Increase in production.

Figure 25 shows the bottleneck costs for 2030. In addition to the default Medium wind scenario, the results are also shown for the Low and High wind scenarios. It is seen from the Δbottleneck cost figures that by going from Low to Medium wind scenario has a positive effect on the utilization of the European grid. However, by increasing the wind power capacity further to the High wind scenario, the Δbottleneck cost is reduced. To summarize, the power system experiences least congestions for the Medium wind power scenario (taking all reinforcements up to 2030 into account), while the High wind scenario would require significant added reinforcements to bring the amount of congestions down to the same level.

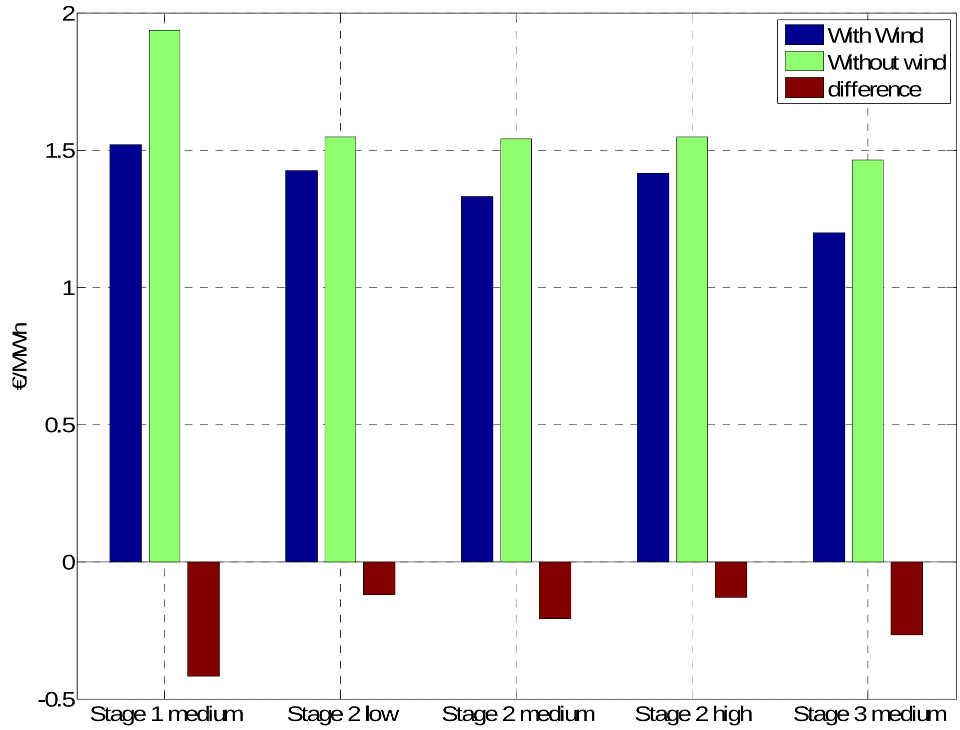

Figure 25. Bottleneck cost in 2030 with and without wind

Furthermore, Figure 25 includes a "column" with added "stage 3" reinforcements for the Medium wind scenario. The stage 3 reinforcements, shown Table 10, include the connections with highest sensitivity values after running the simulation with stage 2 reinforcements. It is seen that the *relative* improvement is decreased significantly as compared with going from stage 1 to stage 2. This result is intuitive, since the most critical congestions were handled in stage 2, and stage 3 only adds parallel branches or HVDCs to existing connections. To effectively reduce congestion costs further, one should aim at identifying new connections (i.e. between substations that are not presently connected) and, as exemplified in Chapter 5 on offshore wind, identifying possibilities of building trans-national sub-sea HVDC grids. Moreover, it is emphasized that the bottleneck cost results are based on a grid model that does not take into account branch capacity limitations internally in each country[4]. The following section shows that internal constraints have a significant contribution to bottleneck costs.

Table 10. Stage 3 branch reinforcements. Internal zones reinforcements are marked with grey color.

Year	Zones		Type	Rate [MW]
2030	NO-1	NO-1	AC	1210
	FR-3	CH-1		1046
	BE	NL		1476

[4] Except for the branches listed in Appendix 2.

	CH-2	IT-1		514
	DE-2	DE-2		2764
	IT-X	GR-X	HVDC	500
	FR-4	IT-1		1000
	NO-1	DE-2		1000

4.6 Sensitivity study of constraining the branch connections between zones

In the UCTE-part of the DC power flow model, only the branch connections between countries have actual power flow constraints, the only exceptions are parts of Germany and a few other branches (See Appendix 2). All other internal branch capacities in the UCTE-model are set to infinite due to lack of information. Using infinite capacity also make it easier to add future wind generation into the model, since it is then possible to inject large amount of wind into a few buses per region. Internal constraints and bottlenecks are thus assumed to be handled by local grid upgrades. Studying local problems is not within the scope of this project. But to see what influence constraints between internal zones will have on the result, a default value of 2000 MW on each branch connection between zones were tested. These default values where only set on connections not already having capacity constraints.

The total congestion costs with and without wind power are shown in Figure 26 (details in Appendix 1), for the three years 2015, 2020 and 2030. For comparison the congestion costs for the reference case, with infinite capacity on internal constraints between zones, are shown in Figure 27.

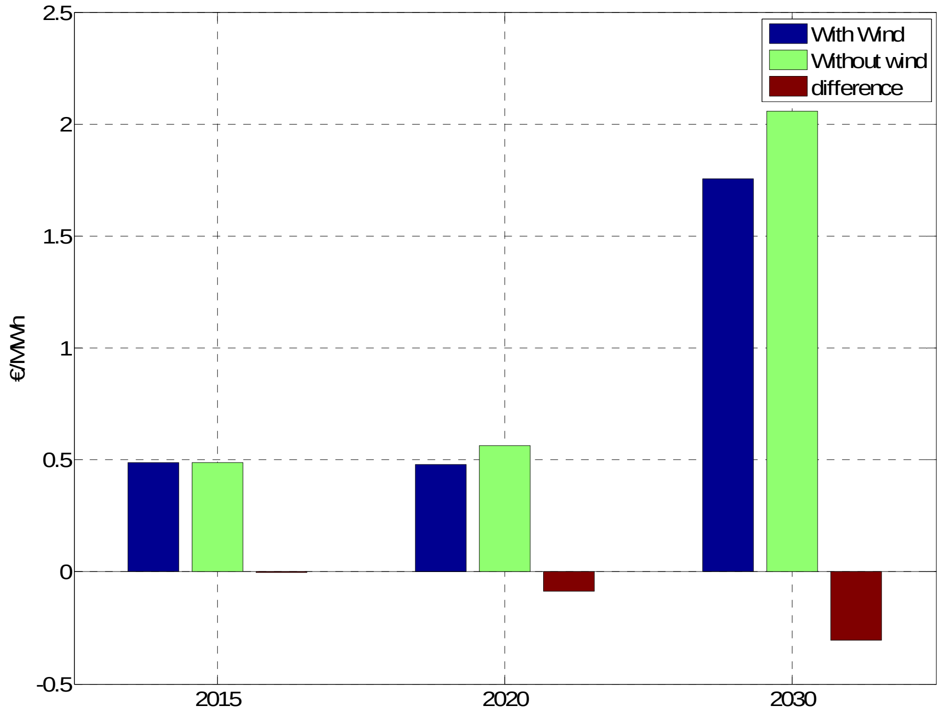

Figure 26. Bottleneck cost with default internal constraint of 2000 MW

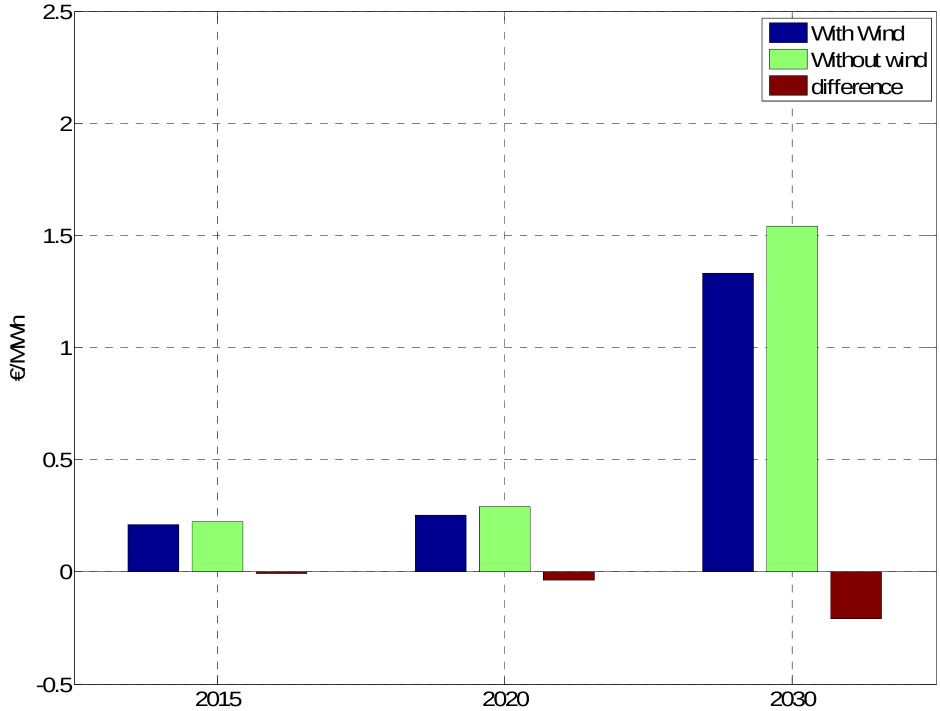

Figure 27. Bottleneck cost with infinite default internal constraint

As expected, the bottleneck costs are increased significantly for all simulations when including zonal constrains. However, it cannot be concluded from the results that zonal constraints worsens the congestion situations more for the case with wind power than for the case without wind power. In other words, zonal constraints have a negative impact on the utilization of wind power, but at the same time it also hinders the substitution of expensive conventional generation for cheaper conventional generation located elsewhere.

4.7 Wind influence on constrained corridors

The proposed grid reinforcements presented in Chapter 3 are based on the assessment of congestions in sections 4.3 through 4.5. The reinforcements were proposed based on sensitivity of branch and HVDC capacity on the total costs in order to reduce the bottlenecks caused by large scale integration of wind as well as redistribution of generation to lower cost production units in general. Thus, the methodology does not directly distinguish between grid upgrades needed specifically for wind power and grid upgrades needed for reduction of generating costs in general.

Figure 28 identifies to some degree the influence of wind power by comparing the critical corridors for Low and High wind scenarios. The colour codes and symbols in the figure are as follows:

- Yellow circles: Internal congestions inside zones. It is emphasized that the grid model does only include internal constraints for some parts of the system such as parts of Germany and Norway, but not for e.g. Spain. See Appendix 2 for overview of internal constraints included in the model.
- Red, solid lines: Congestions due to branch or HVDC constraints.
- Blue, dashed lines: Congestions due to NTC.
- Red, dashed lines: Congestions partly due to branch capacity and partly due to NTC.
- Note that the figures do not show NTC congestions for countries that are subdivided into several zones, such as Germany. Therefore, NTC congestions between Germany and Netherlands are not shown in the figures although they are significant, see Figure 17 and Figure 22.
- The thickness of a line in the figures is dependent on the cost sensitivity[5] of the branch-, HVDC-, and NTC-capacities. The number of connections shown in the figures is limited to the 25 connections with highest cost sensitivity.

[5] Cost sensitivity is the reduction of the market model objective function (i.e. total hourly generating costs) by increasing the capacity of a connection by 1 MW. The hourly sensitivity value for each connection is summarised for all hours of the year to obtain the cost sensitivities used in the analysis.

An observation that can be made from the figures is that most of the interconnectors that are congested in the high wind scenarios also are congested in the low wind scenarios. The most evident changes from Low to High are:

- High wind scenarios causes high congestion between North West and central Germany
- The GB-FR link becomes more congested in the High wind scenario in 2020 (The GB-FR link is strengthened by a second cable in the 2030 scenario)
- The figures indicates higher congestions on the connection between Northern Spain and Portugal as the amount of wind power in the system becomes higher
- Increased wind power installation in Northern Sweden increases the need for internal reinforcements and reinforcements on the connection to Finland.
- In 2020, the relative importance of the GR-IT link capacity limit is higher for the Low Scenario than for the High Scenario, possibly because of the reduced need for import to Italy due to increased wind generation in this country.

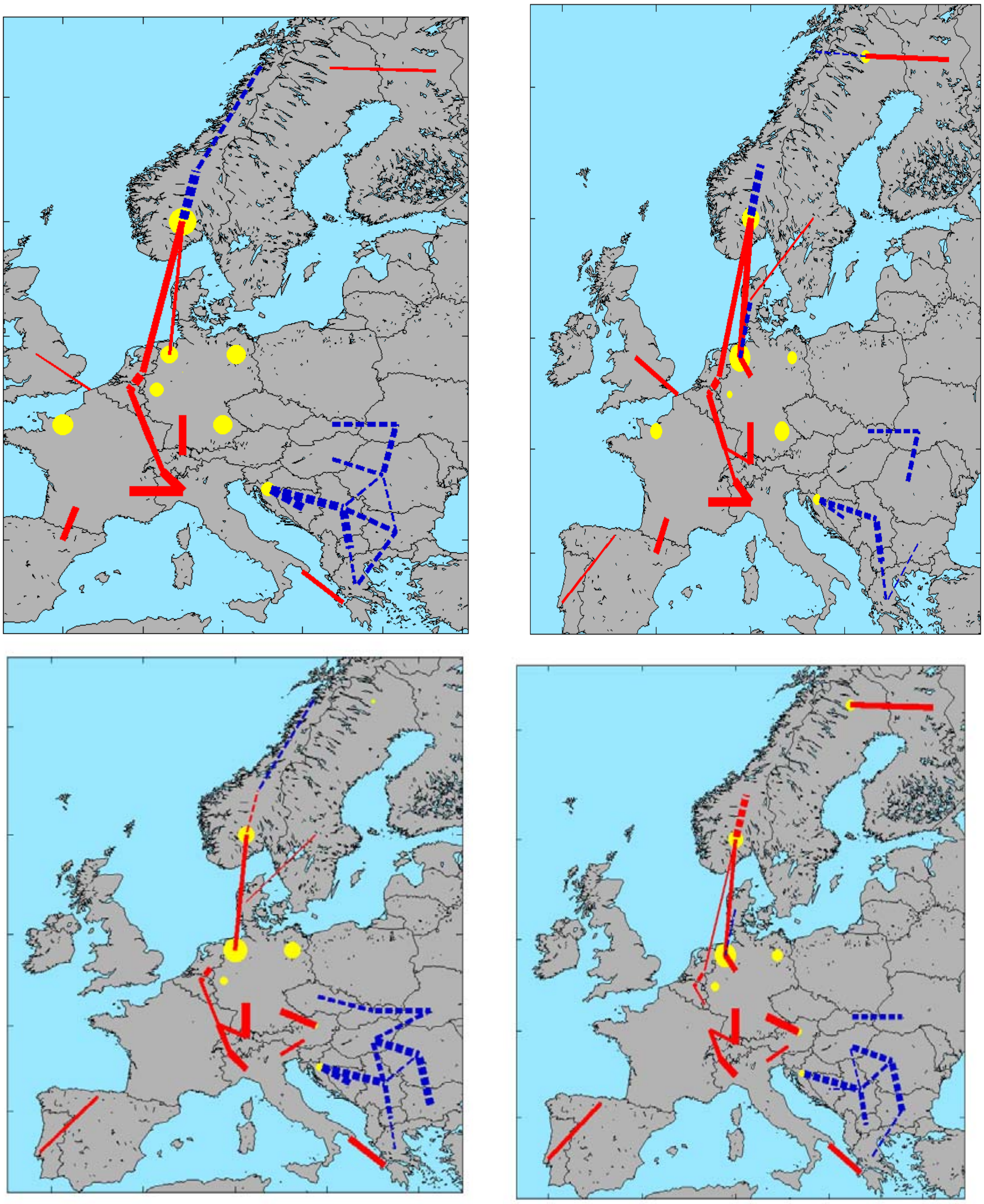

Figure 28. Critical corridors based on sensitivities. Clockwise: 2020 Low, 2020 High, 2030 High, 2030 Low. Red: Lines or HVDC constraints. Dashed: NTC constraints. Yellow: Internal constraints.

4.8 Wind curtailment

Figure 29 shows both potential wind generation and actual wind generation in zones that experiences wind curtailments. Even after installation of stage 2 reinforcements some, approximately 6.5 % for

2030, of the wind in DE-2 had to be curtailed due to grid bottlenecks. The other zones with wind curtailment are Hungary and FR-3 in France.

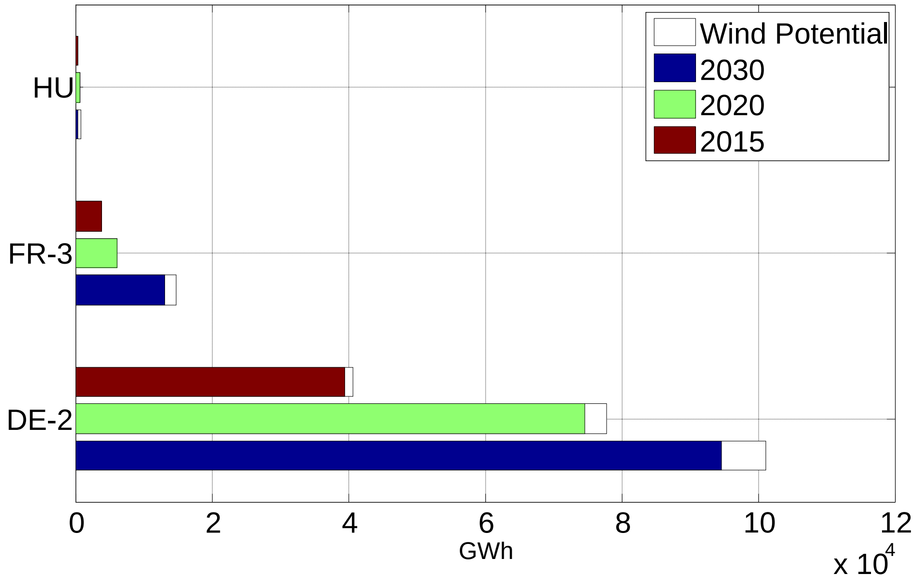

Figure 29. Curtailment of wind (stage 2 reinforcements)

For Hungary there is wind curtailment for both 2020 and 2030, and even though it is very large for 2030 (approximately 50 % of the potential wind generation) the impact on the total result is negligible. Wind in Hungary is located on a branch to RS which is constrained due to NTC in 2030, and the curtailment situation could have been heavily reduced by allocating the wind power in Hungary to more than one bus. The reason for the wind curtailment in FR-3 in France is due to branch constraints in the close vicinity of the injection of wind power into the system, and with large wind power injections into a single bus in the region[6].

The results of this study agrees with [16] that high wind production in the north of Germany is constrained, and grid upgrades must be performed in order to transport high amounts of wind power to the demand centres further south. However it is outside the scope of this study to propose a detailed upgrade of internal grid in any of the UCTE countries.

[6] This is a simplification used for many of the wind power plants in this study, and is reasonable given that there are no internal constraints. It will however result in a lower degree of freedom when finding an optimal solution, and can result in occasional wind curtailment. This could have been avoided by allocating wind to more buses in a zone. See Appendix 6 for how wind capacity is allocated to buses in the grid model.

5 OFFSHORE GRID SCENARIOS

5.1 Updated offshore wind scenarios

For the TradeWind Task 6.2 on offshore grid scenarios, it was decided to use the offshore wind data collected in Task 2.1 as basis, and increase the modeling detail for the countries surrounding the North Sea and the Baltic Sea. This was considered important, since the expected developments of offshore wind in these areas are high, and will influence significantly on the occurrences of bottlenecks in the mainland grid. A relatively high resolution on the offshore wind farm locations is therefore required in order to make more accurate suggestions on suitable mainland connection points. Also, the Baltic Sea and the North Sea are very interesting cases for considering the development of a subsea multi-terminal HVDC-grid, and detailed geographical information on offshore wind farm locations are also required in order to assess this possibility.

A list of offshore wind farms, including coordinates, expected year of installation and expected capacity has been collected by EWEA as part of the Tradewind project, see Appendix 3. Based on planned wind farm projects, governmental plans and EWEA scenarios, the following changes to the original Tradewind scenarios have been done for the offshore grid study:

- Netherlands: Offshore increased from 12 GW to 20 GW in 2030 High.
- Great Britain: Offshore increased from 7.8 GW to 33 GW in 2030 Medium and 2030 High (Offshore wind in Great Britain was also updated for the grid studies in Chapters 3 and 4 and for the grid studies in TradeWind WP5).
- France: In the original TradeWind wind capacity data, no specifications were made for offshore wind. A part of the onshore wind capacity has been replaced by offshore wind (For GW for 2030 High, see Table 11. Thus, the total wind power capacity in France is unchanged.

The country-wise scenarios for offshore wind are listed in Table 11. The locations of offshore wind farms in northern Europe and their assumed development for the different TradeWind scenarios are shown in Figure 30.

Table 11. Updated offshore wind power capacity scenarios (GW).

	2005	2008 L	2008 M	2008 H	2010 L	2010 M	2010 H	2015 L	2015 M	2015 H	2020 L	2020 M	2020 H	2030 L	2030 M	2030 H
BE	0.0	0.1	0.1	0.2	0.2	0.2	0.3	0.5	0.5	0.8	0.5	1.3	1.5	0.7	3.0	3.8
DE	0.0	0.0	0.1	0.2	0.1	0.9	1.7	3.8	9.8	12.5	9.8	20.4	24.6	20.0	25.0	30.0
DK	0.4	0.5	0.5	0.6	0.6	0.7	0.8	0.9	1.0	1.1	1.4	1.6	1.8	2.7	3.0	3.3
ES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	2.0	4.0	2.5	5.0	7.0	4.5	9.0	10.0
FR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	2.0	2.0	4.0	4.0	4.0	4.0	4.0	4.0
GB	0.2	0.6	1.6	2.1	2.0	3.3	3.8	2.5	4.8	5.8	3.0	6.3	7.8	3.5	33.0	33.0
GR	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.4	0.4
IE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.4	0.7	0.3	0.4	0.8	0.3	0.5	1.0
NL	0.0	0.1	0.2	0.2	0.2	0.5	0.7	1.3	2.0	3.0	2.2	3.5	6.0	2.2	12.0	20.0
NO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.7	0.0	0.5	1.9	0.0	2.5	7.3
SE	0.0	0.1	0.2	0.2	0.3	0.4	0.6	1.1	1.8	2.6	2.4	3.8	5.5	4.1	5.8	11.0
FI	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.2	0.6	1.1	0.7	1.2	2.1	1.2	1.8	3.9
Sum	**0.8**	**1.7**	**3.1**	**3.7**	**3.8**	**6.3**	**8.3**	**13.7**	**25.2**	**34.4**	**27.0**	**48.1**	**63.2**	**43.5**	**99.9**	**127.7**

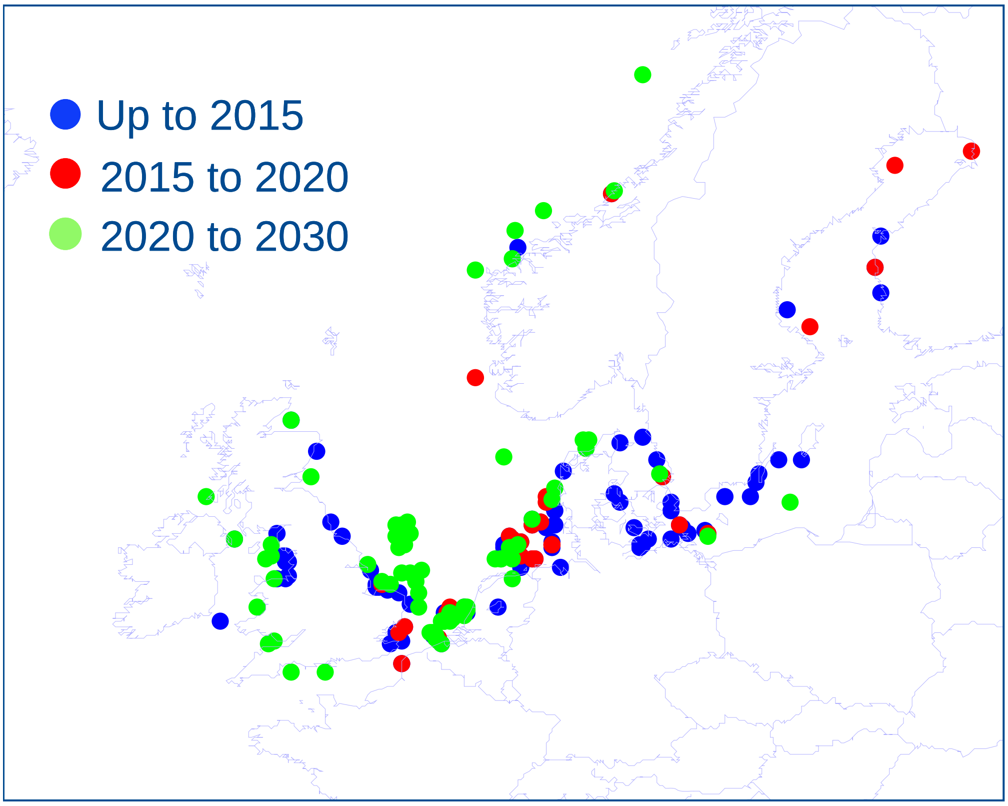

Figure 30. Projected location of offshore wind farms in Northern Europe. Taken from the wind farm list in Appendix 3.

5.2 Clustering of offshore wind farms

The offshore grid assessment is based on the 209 individual wind farm locations shown in shown in Figure 30, and listed in Appendix 3.

For this study, these wind farm locations have been grouped in several clusters with assumed common grid connection point. Clustering of offshore wind farms in Germany is based on information from dena, see Appendix 4. A similar approach has been used for clustering of offshore wind farms in the other countries; a cluster contains of wind farms in short distance to each other with same assumed connection to onshore grid point in the grid model.

The clusters are further divided into two groups:

- "Close": Wind farm clusters with radial connection to the nearest onshore substation.
- "Far": Wind farms clusters with radial connection to shore and/or connection to other wind farms as part of an offshore transmission grid.

The "Close" offshore wind clusters are shown in Figure 31. These clusters are not considered to be part of a linked offshore grid, either due to their short distance to the mainland grid or due to their remote location relative to other wind farm (e.g. offshore wind farms in the North of Norway). Their assumed connections to onshore substations are given in Appendix 3.

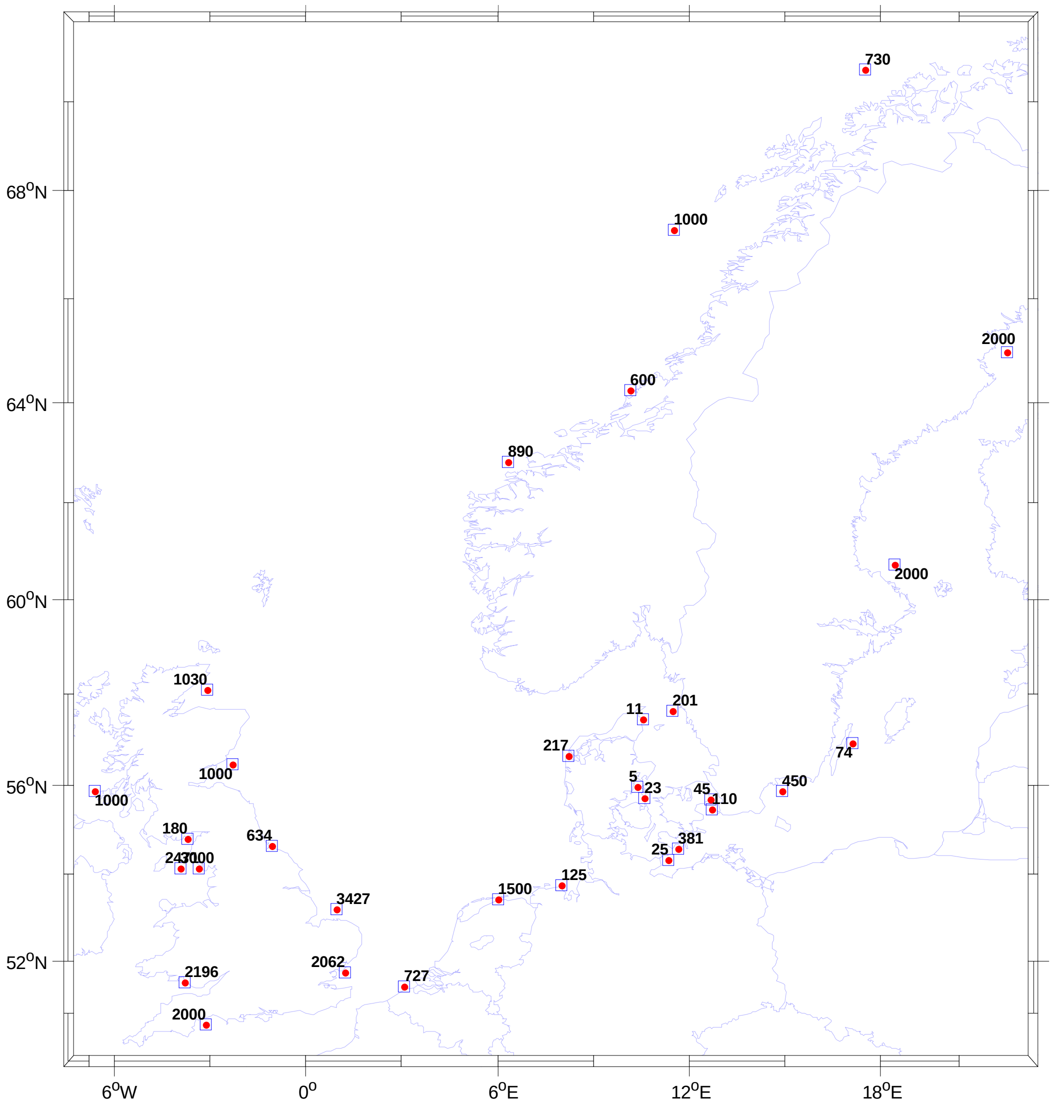

Figure 31. Close offshore wind clusters, not considered to be part of an offshore grid. The 2030 H capacities are given in MW.

The “Far” offshore wind clusters shown in Figure 32 and Figure 33 are considered to be potentially part of an offshore grid. Although the terminology “far” and “close” is used, there is no specified cut-off distance between the types of clusters. The difference is that the “far” clusters are considered to potentially be part of an offshore grid.

As a base case, the “far” wind clusters are connected radially to the nearest onshore grid point, similarly to the “Close” wind clusters. Different configurations of an offshore grid, linking several clusters together are then suggested and compared to the base case (radial connection) in terms of bottleneck costs, constrained wind and total generation costs.

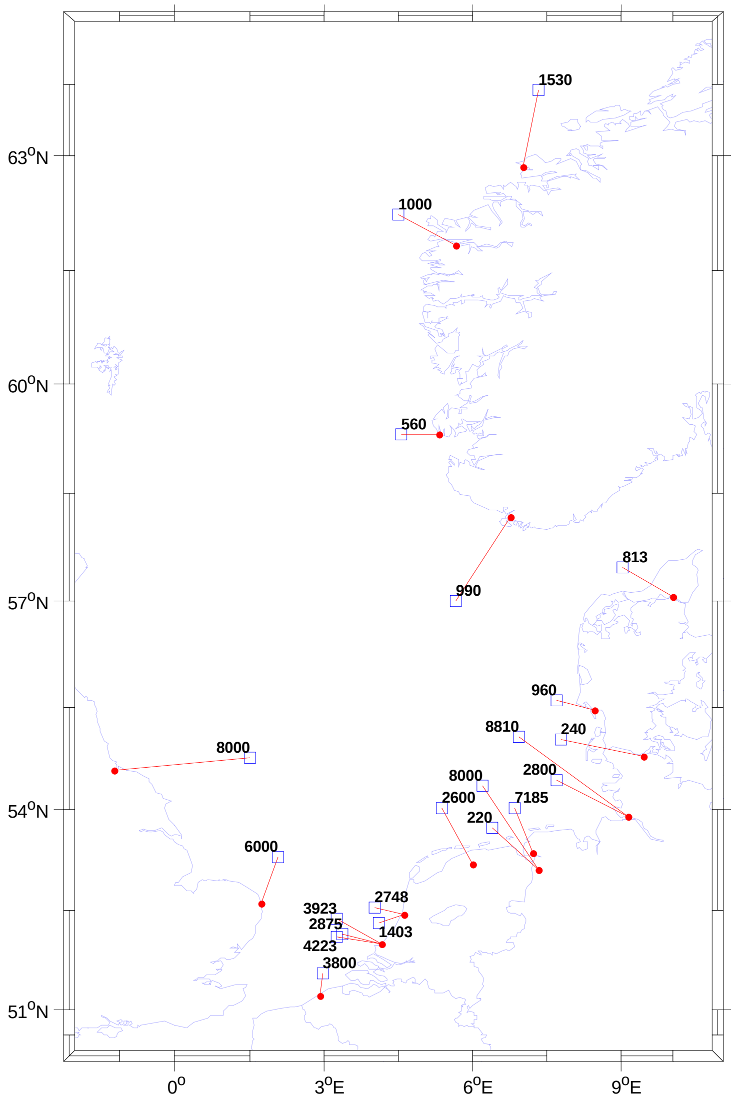

Figure 32. Far offshore wind farms in the North Sea, shown with possible radial connection. The 2030 H capacities are given in MW.

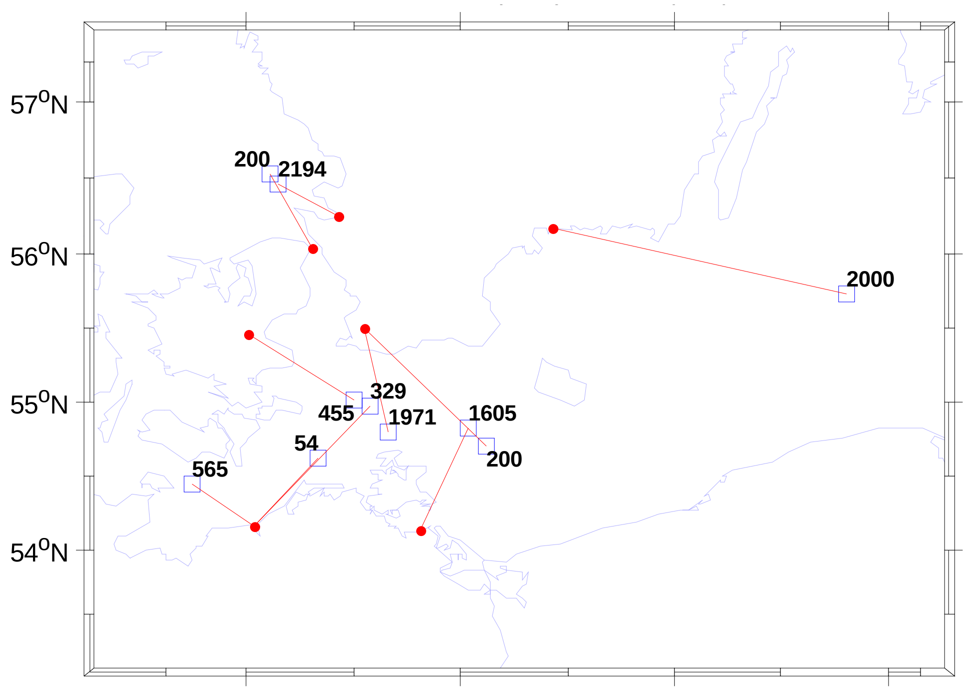

Figure 33. Far offshore wind farms in the Baltic Sea, shown with possible radial connection. The 2030 H capacities are given in MW.

The distances from the "Far" offshore wind clusters to possible onshore substations are given in Appendix 3. The connections shown are to national substations, e.g. the 2000 MW wind farm furthermost to the East belongs to Sweden and is therefore as a base case directly connected to the substation Stärnö in Southern Sweden, rather than to Poland which indeed has a closer possible connection point.

5.3 Connection alternatives for offshore wind farms

Figure 34 shows the radial connections of the offshore wind farm together with the subsea interconnectors in the North Sea and the Balitc Sea that are included in the grid model for 2030, including the grid upgrade scenarios from Chapter 3.

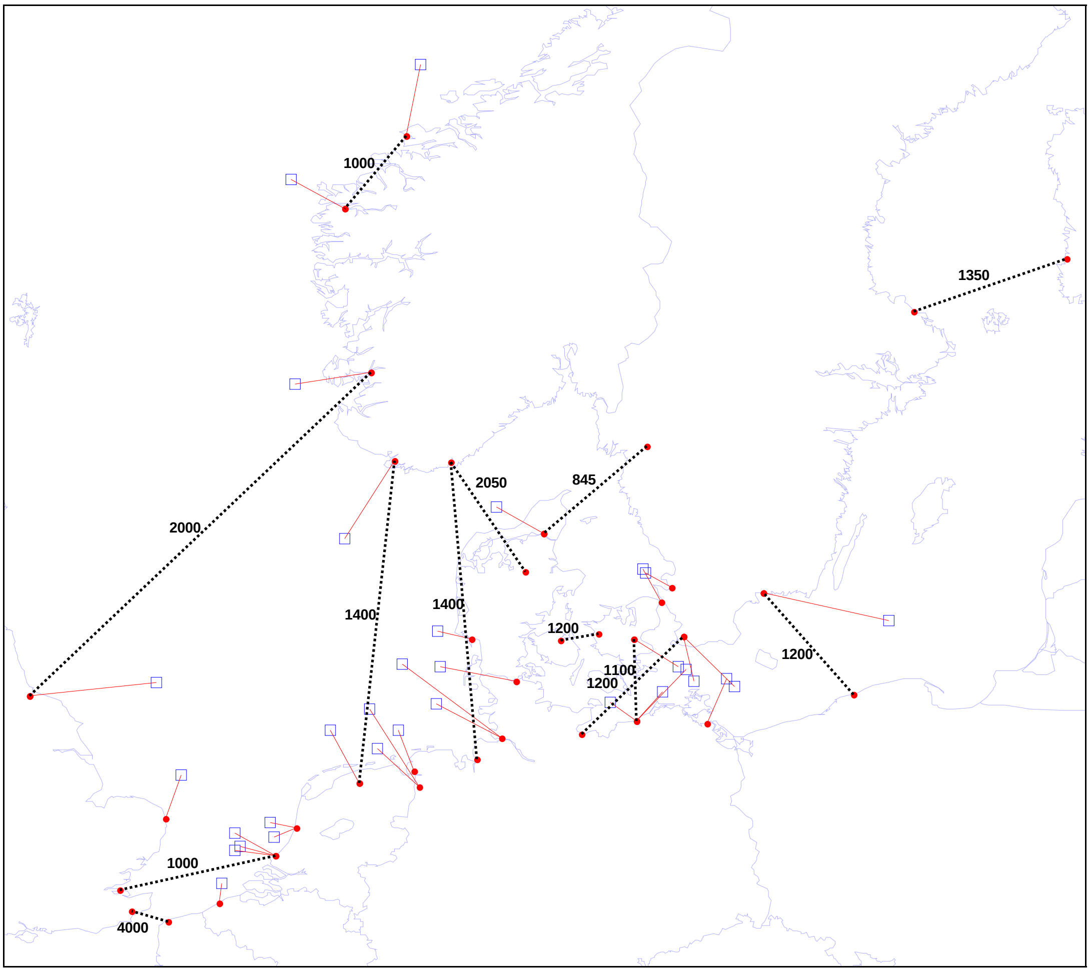

Figure 34. Radial connection of offshore wind farms shown together with HVDC interconnectors and their total capacities (dotted lines).

There are several reasons to expect that the offshore networks will become meshed:

- The variability of wind energy can best be mitigated on a European scale. This requires significant reinforcement of the European high-voltage networks in order to create truly "Trans-European Energy Networks”.
- Combination of the offshore network connections with strong interconnectors is expected to be attractive.
- Reinforcing mainland AC high-voltage networks is costly and tedious. By creating a strong 'outer loop' at sea, some mainland network connections may be avoided.

With the assumption that offshore wind power plants can be linked to each other and to trans-national HVDC link by subsea connectors, it would be possible to design an offshore grid that utilizes the cable capacities better than the solution presented in Figure 34. Especially important is the case of North West Germany, which has been identified as an energy surplus area with high internal congestions in the mainland grid. Taking into account that the Netherlands and Belgium will benefit from increased imports, and that Norway has very high amounts of highly controllable hydro power plants, it seems reasonable to study a grid structure which links these countries together. Figure 35 shows such a proposal, which also includes links to Denmark West and Great Britain. By adequate cable dimensioning, the link from Norway to Germany, via the southernmost Norwegian offshore wind cluster, could be a possible alternative to the NorNed2 cable and the NorGer cable.

In the Baltic Sea, it could be beneficial from a power system operation point of view to link the wind clusters in the Kriegers Flak together, enabling flexibility for transporting higher amounts of offshore wind power to areas with higher prices. Also, such a link makes it possible to effectively trade power between Sweden, East Denmark and Germany in periods with low wind speeds.

The lengths of the added cables in the meshed offshore grid are given in Appendix 3, and a first iteration proposal for cable dimensioning is given in Figure 36 for the North Sea and Figure 37 for the Baltic Sea. The next section presents results from simulating the system with the radial connection and the meshed subsea connection. Updated cable capacities in the meshed network have been proposed based on the simulation results. The updated cable capacities are given in Figure 38.

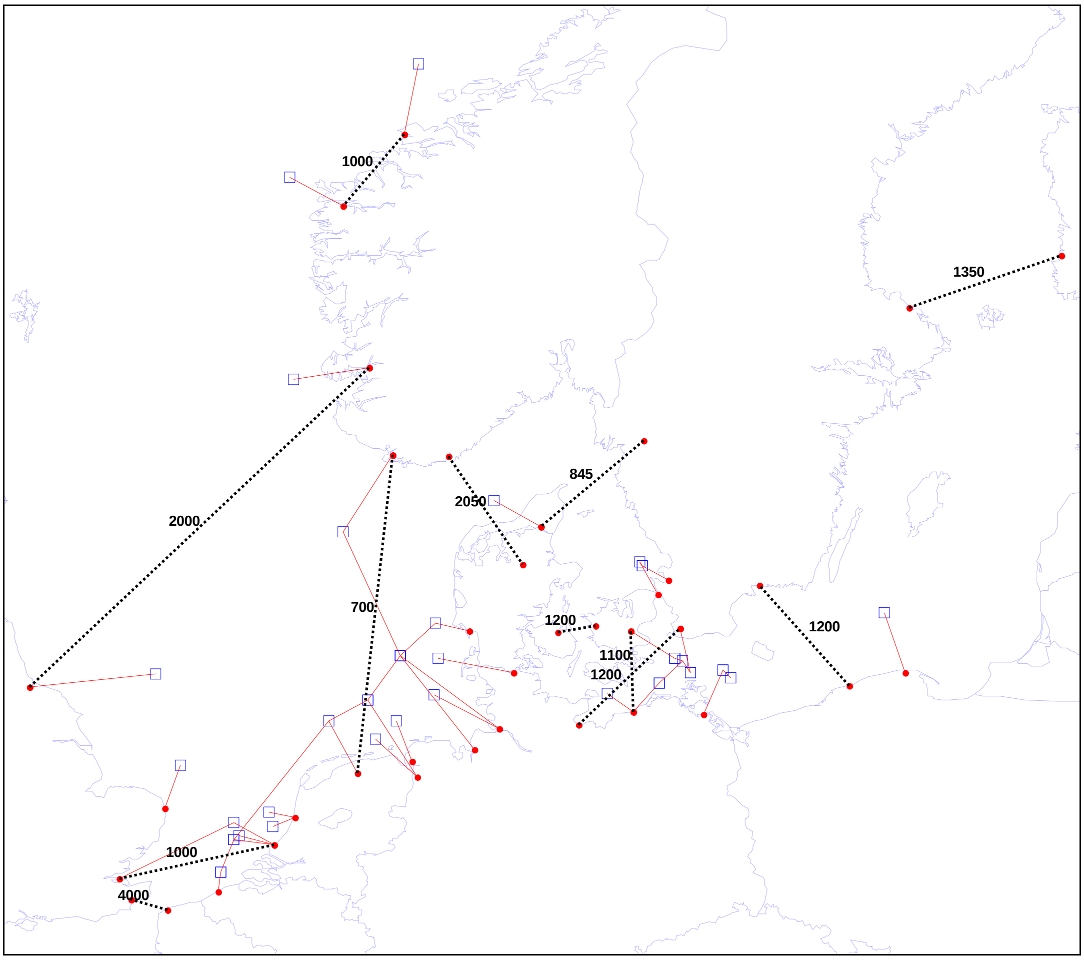

Figure 35. Possible meshed HVDC connection of offshore wind farms. Dotted lines are HVDC interconnectors. NorNed2 and NorGer are replaced by a HVDC connections between Norwegian and German offshore wind farms.

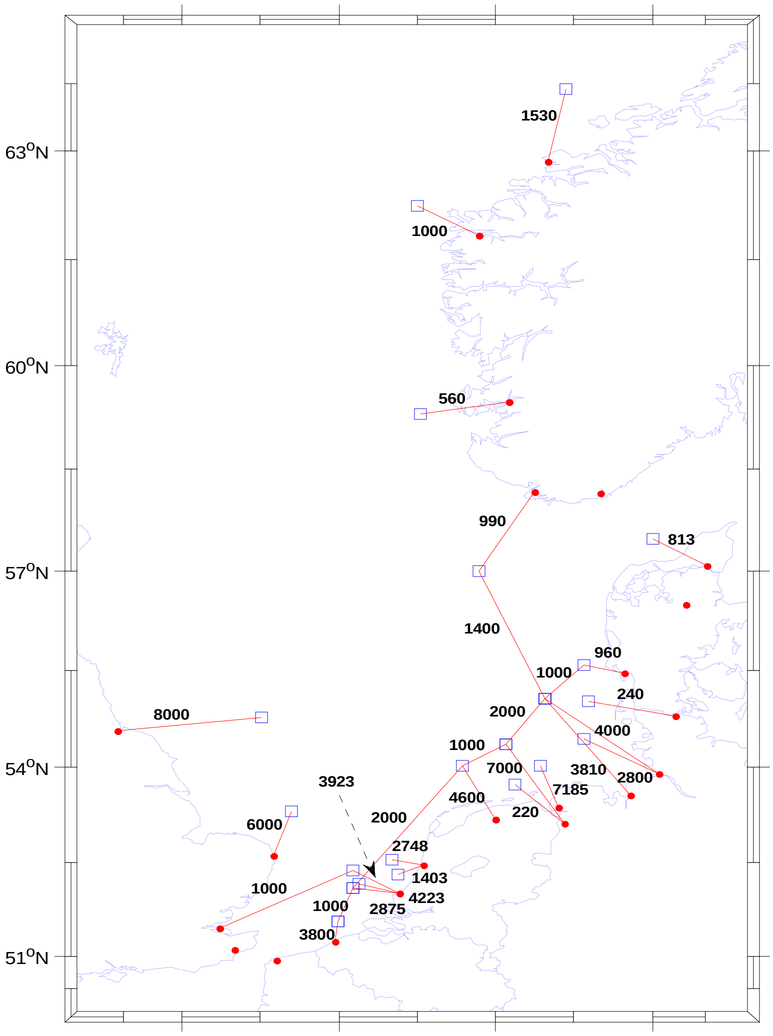

Figure 36. Capacities of HVDC connections in the North Sea for the 1.iteration subsea grid configuration.

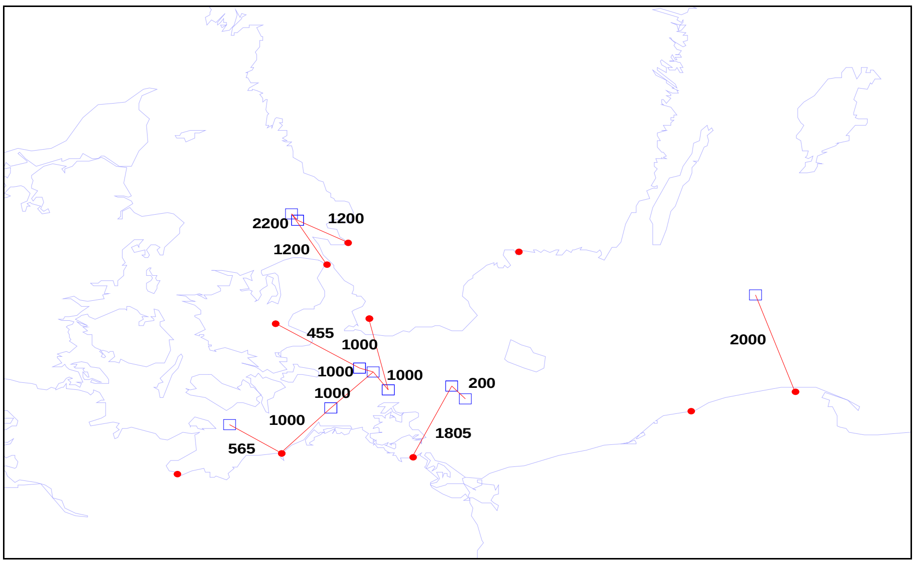

Figure 37. Capacities of HVDC connections in the Baltic Sea. The Kriegers Flak wind farms are linked and have common connection to Denmark, Sweden and Germany.

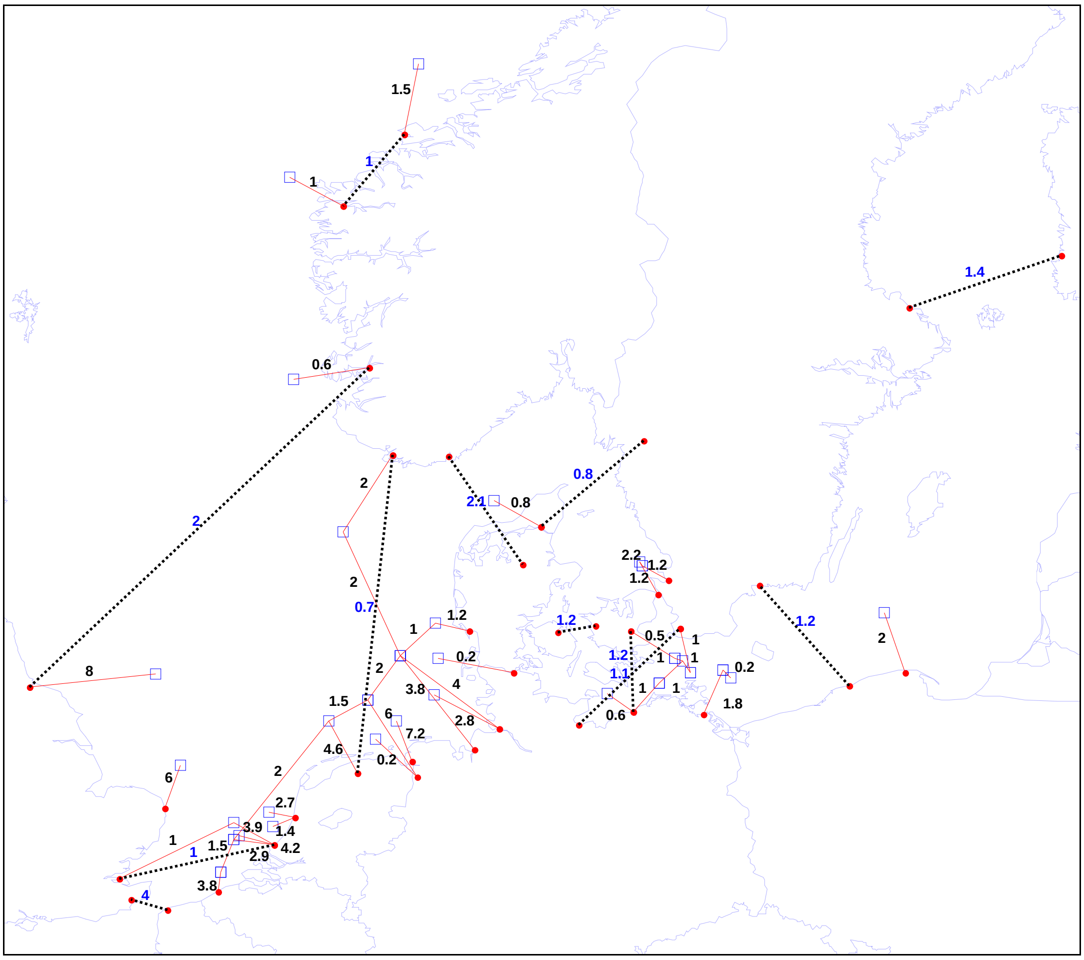

Figure 38. Capacities (GW) of HVDC connections in the North Sea and Baltic Sea for the 2.iteration subsea grid configuration. Values in blue are capacities on HVDC cables not directly connected to wind farms.

5.4 Bottleneck costs of offshore wind power

This section presents results from simulating scenario 2030 High with radial connection and meshed grid connection of the offshore wind clusters presented in the previous sections.

The analysis method used for calculating bottleneck costs is similar to the method used in Chapter 4. This is done in order to study the effect that different offshore wind connection alternatives has on the congestion costs, assuming a base scenario with high amounts of onshore wind power in the system.

The bottleneck cost results are given in Figure 39. It is noticeable that the 1.iteration meshed offshore grid ("Meshed1") indeed gives *higher* bottleneck costs than the radial connection alternative. This is simply due to the fact that no attempts were made on actually optimizing the cable dimensioning of the Case 1 meshed offshore grid of the North Sea shown in Figure 36.

Based on the sensitivity results for the cable capacities, see Table 12, updated cable capacities were proposed as shown in Figure 38. The bottleneck costs of the updated meshed grid ("Meshed2" in Figure 39) are then remarkably lower than for radial connection. Nevertheless, the bottleneck costs are still lower for the simulation without offshore wind, which clearly indicates that offshore wind power causes significant congestions in the mainland grid. In order to effectively integrate high amounts of offshore wind in the power system, it is necessary to further upgrade the onshore network. Table 13 lists highly congested mainland connections for simulation of Case 2 meshed offshore grid. In addition to internal constraints in Germany and Sweden, connections between Belgium and Netherlands and between Belgium and France are highly congested. As an alternative to further reinforcements of mainland connections in these areas one should consider building much stronger offshore subsea grids as further discussed in Section 5.5.

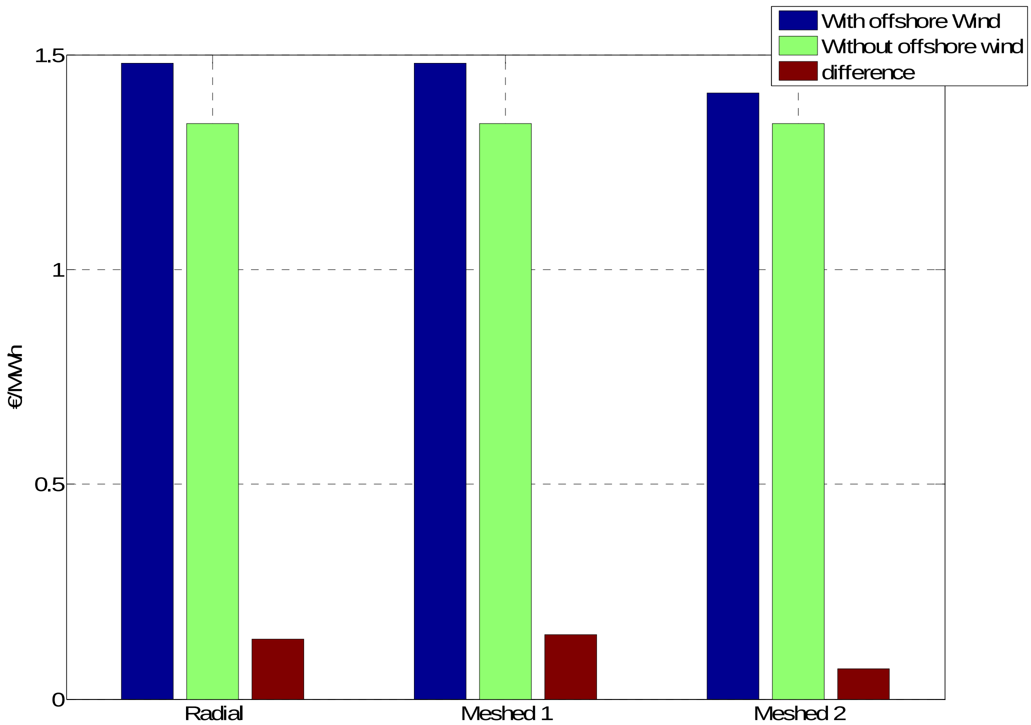

Figure 39. Bottleneck cost offshore 2030 high wind.

Table 12. Sensitivities in flow on HVDC connections in the North Sea for Case 1 meshed offshore grid.

Bus		Zone		Area		€/MW
O: NO-O1:1	Nordel: 5600	NO-O1	NO-1	NO	NO	155445
O: NL-O6:1	O: DE-O6:1	NL-O6	DE-O6	NL	DE	131749
O: DK-O1:1	DK-81039	DK-O1	DK	DK	DK	104000
NL-1 607	Nordel: 5605	NL	NO-1	NL	NO	90106
O: NL-O1:1	O: BE-O1:1	NL-O1	BE-O1	NL	BE	67126
Nordel: 5604	DK-11032	NO-1	DK	NO	DK	50281

Table 13. Sensitivities in flow on specific branches for Case 2 meshed offshore grid.

Bus		Zone		Area		€/MW
D_DI 807	D-44 811	DE-2	DE-2	DE	DE	297243
B_ZA 534	NL_G 624	BE	NL	BE	NL	229001
B_ME 556	NL_M 627	BE	NL	BE	NL	169422
B_AU 554	F_MO 241	BE	FR-3	BE	FR	168716
D-12 779	D-20 787	DE-2	DE-2	DE	DE	137947
Nordel: 3244	Nordel: 3245	SE-3	SE-3	SE	SE	129090

Table 14 shows the total power generating costs for the different connection alternatives. It is seen that the meshed offshore grid with updated cable capacities (Case 2) gives significantly lower annual costs. To see what influence constraints between internal zones will have on the result, a default value of 1500 MW on each branch connection between zones were tested. These default values were only set on connections not already having capacity constraints, see Section 4.6 for further explanation of the method for assessing internal constraints. By reducing the capacity of internal connections in the model, the benefits of the meshed network becomes higher, as seen from Table 14. This is due to the added flexibility introduced when including an HVDC network that links many countries (Norway, Denmark, Germany, Netherlands, Belgium and Great Britain in the North Sea and Sweden, Denmark and Germany in the Baltic Sea). HVDC connections are modelled as fully controllable, which makes it possible to effectively avoid bottlenecks in the AC grid for transporting offshore wind power to consumers in areas with energy deficit or high local generating costs.

Table 14. Total power generating cost 2030 High (M €)

Internal zonal constraints	Radial	Meshed	Difference
Infinite (case 2)	131202	130876	325.36
1500 MW (case 2)	135830	135471	359.32

The difference in total power generating cost of 325 M€ can be interpreted as a very rough measure of the break even cost for the extra investments needed to realize a meshed offshore network, bearing in mind the limitations of the model to quantify actual operating costs. Taking into account factors that are not handled in the model, such as startup cost of thermal generators, internal grid constraints and balancing of wind power, the operational benefits of a meshed offshore grid could very well be significantly higher than estimated by the model. It is also important to notice that the offshore grid structure is by no means optimized in this study. However, to give an idea about how the calculated savings in operational costs compares with the added investments of the meshed network, a simple cost calculation have been carried out, assuming cost figures similar to Borkum 2 and oil-platform electrification projects in the North Sea. Based on these assumed data as given in Appendix 5, the added annualized offshore grid investment cost is in the range of 300-400 M€/year. However, it is important to emphasize that the validity of the comparison is indeed very limited, especially due to the fact that added and avoided mainland AC grid reinforcements are not taking into account in the cost calculation. Section 5.5 gives a further consideration on stronger meshing of offshore grids.

It was seen from Table 14 that the inclusion of internal zonal constraints gives higher total operating costs. Also, the total amounts of discarded wind power increased, both offshore and onshore. For the meshed offshore network, the total amounts of discarded wind increases from 19.6 TWh (1.8 % of the potential wind generation of 1069 TWh) to 24.6 TWh (2.3 %), see Figure 40. For the radial connection case, the amounts of discarded wind increases from 28.7 TWh (2.7 %) to 34.0 TWh (3.2 %).

The cable dimensioning in the radial case are set somewhat higher than the maximum wind power output for all offshore wind clusters. Nevertheless, some of the offshore wind clusters experience high amounts of discarded wind energy, especially in Germany but also to some extent in Netherlands. The amounts of discarded wind energy are effectively reduced by introducing the meshed network, also for the offshore wind clusters that are not directly connected to the offshore network. An example is the highly congested North West Germany, were the proposed offshore network makes it possible to transport the wind generation from DE-O10 (Helgoland 2) to other areas, thus increasing the utilization of DE-O6 (Helgoland 1) which has a radial connection only. However, the power generation from some of the offshore wind clusters is still relatively highly constrained, emphasizing the need for reinforcements of the AC mainland grid and strengthening the trans-national HVDC links. Additional results for the meshed offshore case (maps of energy flow, sensitivity of capacity constraints and number of congested hours) are given in Appendix 5.

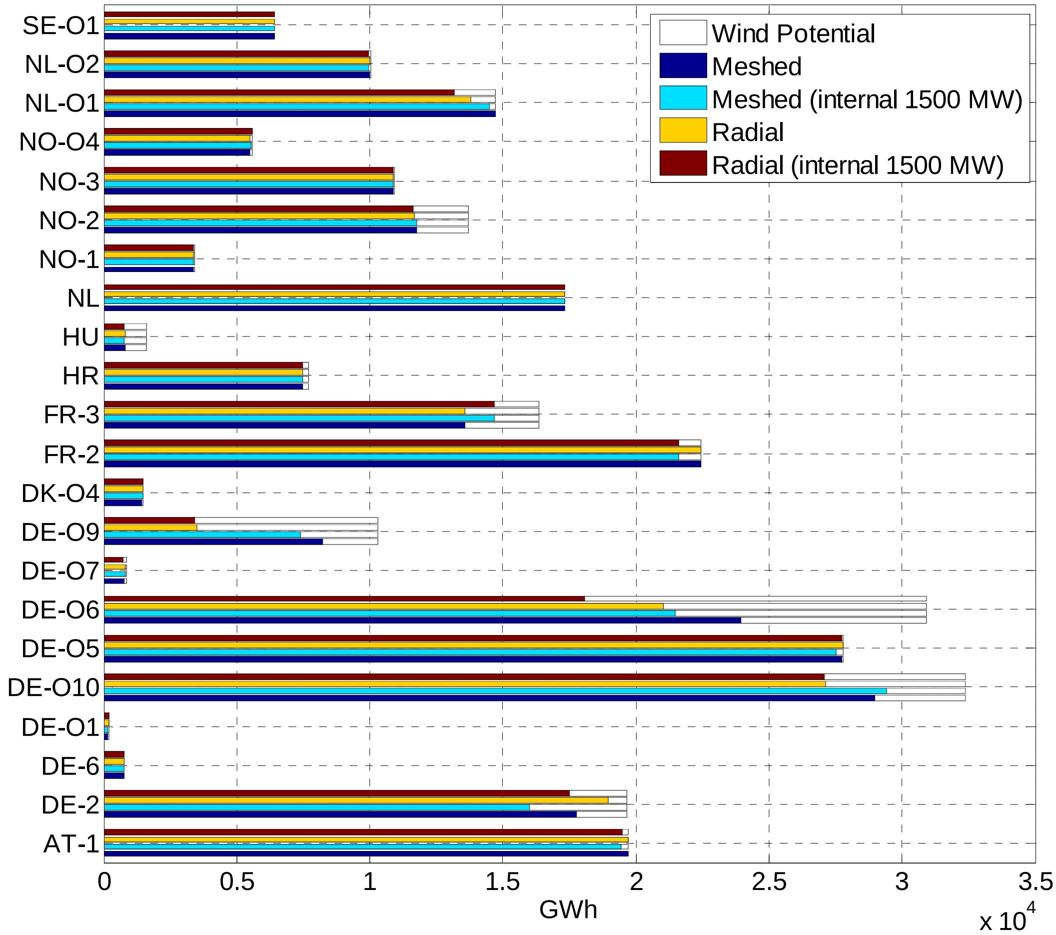

Figure 40. Potential and actual wind production

5.5 Stronger meshed offshore grid

Some elements of bottleneck costs are not (yet) incorporated in the model:

- The efficiency of power plants and hence their marginal costs are dependent on the operating point but are assumed to be constant. Especially for large penetrations of wind energy, this may influence significantly on the bottleneck costs
- Start-up costs for power plants are no taken into account. Especially for large penetrations of wind energy, these costs are expected to be significant. Limitations in starting up and shutting down thermal generators in response/anticipation to wind power production changes may well require additional interconnectors and international trading arrangements
- A perfect market is assumed i.e. the cheapest generation in Europe available always replaces the more expensive generation in Europe.

Taking these factors into account, it is expected that, for high wind power penetration, the bottleneck costs will be significantly higher than predicted in the current model. Strong international interconnections may become economically justified.

Figure 41 gives a conceptual example for a further meshed offshore network at the North Sea and the Baltic Sea, assuming 5 GW rated power per additional connection[7].

[7] Technology to be developed, or by using parallel cables

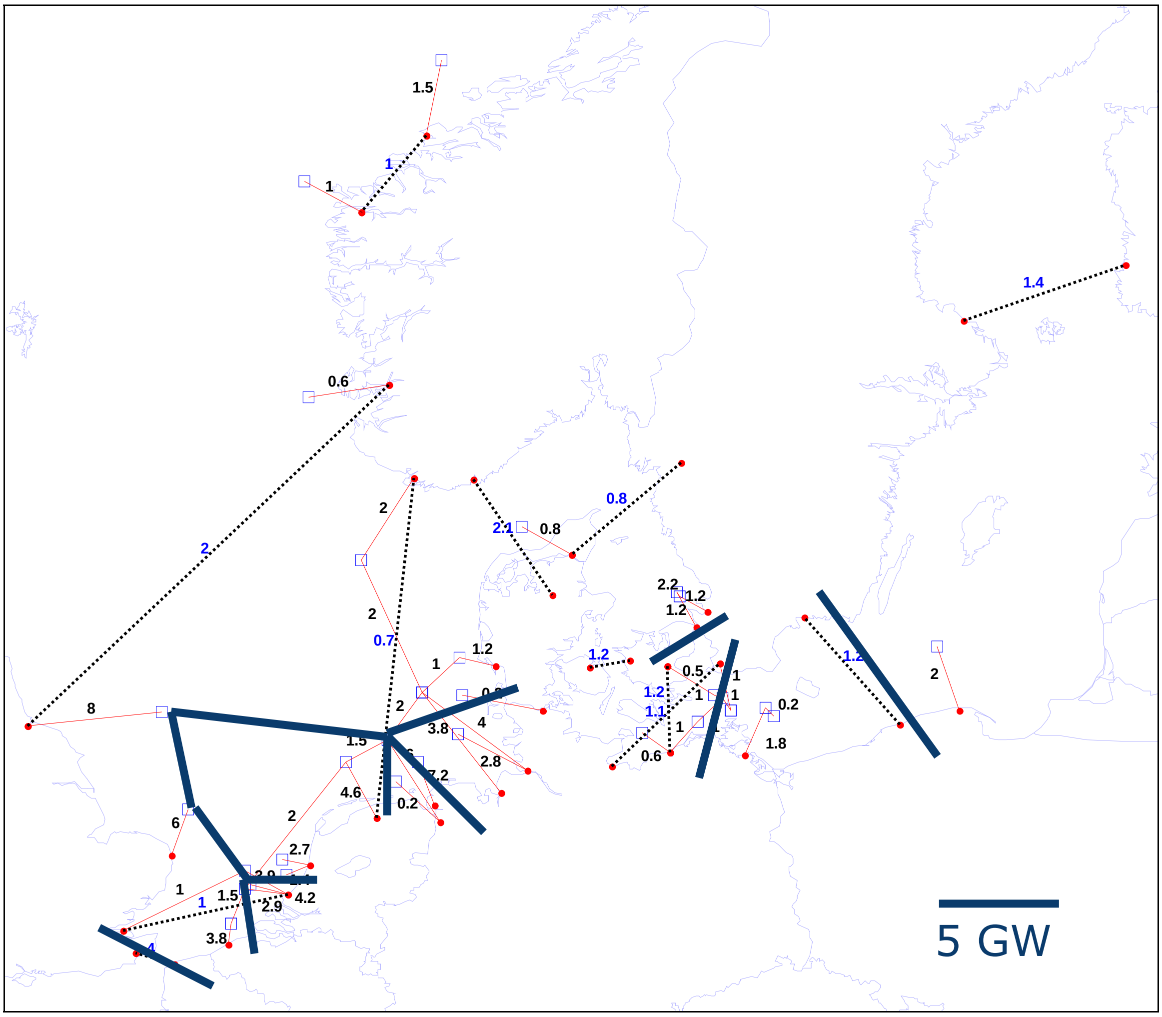

Figure 41. Meshed network on the North Sea and the Baltic Sea, based on Figure 38, with 5 GW connections added (bold dark blue lines)

Offshore grids could facilitate multi-GW deployment of offshore renewable sources, in combination with the realization of strong interconnections between the countries. Thus, a more transparent Europe-wide electricity market would be created, in line with the European Union's policy of "Trans European Networks for Electricity" (TEN-E).

Not only the offshore networks, but also the onshore networks would need significant reinforcement. Czisch [6] has proposed an overlying backbone grid for Europe and the neighboring parts of Africa and Asia, see Figure 42. This graph also assumes multi-GW solar electricity generation in Northern Africa.

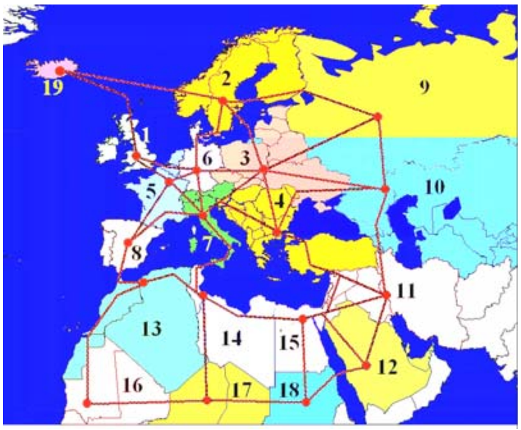

Figure 42 [6].

Until now (2008), such offshore and onshore large-scale grids are yet at the conceptual stage and not yet part of TSO expansion planning.

Apart from significant investments, such offshore grids would require additional technology development in HVDC systems.

6 DISCUSSION

The analyses presented in this report are mainly based on the developed model of the European power system and the collected data on load, generation and grids. The simulations are carried out using the Power System Simulation Tool (PSST) which solves an optimal power flow problem for a given power system model for each hour of a year. The optimal power flow minimises the total generation cost, using a simplified DC power flow representation and with the assumption of a perfect market. By *perfect market* we mean that there is one European market with free competition and that no market power is being executed, i.e. we assume that the market bids equal the marginal costs of generation.

Chapter 3 summarizes the grid upgrade scenarios that were proposed based on the analysis presented in Chapter 4. The choice of grid upgrades were based on a ranking of critical connections in terms of how much the market model objective function (i.e. total generating costs) is influenced by the capacity of the connections. The main focus was on interconnections, though also internal constraints have been upgraded to some extent. One possible measure for how well the model "predicts" the needs for upgrades on specific connections is to compare the ranking of critical connections to the prioritised connections from the UCTE Grid Development Plan. To give a rough idea of the validity of the methodology used for the grid upgrade scenarios, a comparison has been made between the results from the 2020 scenario and connections mentioned in the UCTE Grid Development Plan. Table 15 shows the 25 connections with highest cost sensitivity (due to branch, HVDC or NTC congestions) from the 2020 Medium scenario. It is seen that except for DE-CH, GB-FR and HR-RS, the UCTE Grid Development Plan mentions projects on the identified interconnections. A direct comparison is however difficult to perform, e.g. since the simulation results are based on specific scenarios for wind development and fuel costs (the fuel costs assumptions will in a very high degree influence the utilization of the lines since a perfect market is assumed).

Table 15. Comparison of the congested connections with highest cost sensitivity[8] in the grid model 2020 with UCTE Grid Development Plan [5].

From	To	UCTE plans	Congestion	
			Branch / HVDC	NTC
BE	NL	X	X	
NL	NO	X	X	
FR	BE	X	X	
NL	UK	X	X	
DE	NL	X		x
FR	BE	X	X	
DE	NO	X	X	
CZ	AT	X		x
CZ	DE	X		x
PL	SK	X		x
FR	IT	X	X	
IT	CH	X	X	
FR	CH	X	X	x
FR	IT	X	X	
GR	IT	X	X	
MK	RS	X		x
FR	ES	X	X	
DE	CH		X	x
GB	FR		X	
HR	RS			x

Due to the complexity of the study and the limited detailed data available, several simplifications and assumptions have been made in the study. It is important to bear this in mind when interpreting the results. Regarding the simulation model, the main simplifications and limitations which affect the results are:

- A perfect market is assumed i.e. the cheapest generation available always replaces the more expensive generation
- Start-up costs are not taken into account.
- There are no requirements for reactive support.
- Wind uncertainty and allocation of power reserves are not incorporated.
- The model does not include losses on branch flows and HVDC flows, nor does it include cost on power transmission.
- Strategy for use of hydro reservoirs is based on external water values.
- Power plants are modelled as 100% available. The exceptions are nuclear plants, which have a reduced available maximum capacity depending on the time of the year due to revisions [2],

[8] Cost sensitivity is the reduction of the market model objective function (i.e. total hourly generating costs) by increasing the capacity of a connection by 1 MW. The hourly sensitivity value for each connection is summarised for all hours of the year to obtain the cost sensitivities used in the analysis.

and hydro plants, which may have limited available capacity depending on reservoir level and inflow.

Because the model neglects start-up cost, losses and requirement for reserves and reactive support, all production might be turned off in a zone or area transferring power over long distances.

In addition to model limitations, the results are also affected by the simplifications which were necessary to make due to limited availability of detailed input data:

- Knowledge on actual geographical distribution of different thermal generation types within each country is limited.
- Marginal costs are assumed equal for generators with equal fuels, e.g. gas, lignite coal and oil.
- The efficiency of power plants and hence their marginal costs are dependent on the operating point, but are assumed to be near to constant in the study (The marginal cost is modelled as linearly increasing, but due to lack of data, all marginal cost curves are assumed to have similar slopes relative to the maximum power output).
- With a few exceptions, such as parts of Germany and Nordel, data of internal capacities are unknown. Thus, internal bottlenecks and internal network reinforcements are not considered.
- The grid model of Great Britain and the Island of Ireland has a much higher degree of simplification than the UCTE and Nordel grid models.
- Power plant age is not considered.
- CHP units controlled by heat demand, such as in Denmark, are modelled as fully flexible thermal generators.
- NTC values are chosen to be constant for the whole year and are external input to the model (Increase in NTC values due to reinforcements are to some degree accounted for, see Chapter 4.3.)
- Limited detailed data were available on inflow to hydro reservoirs and geographical distribution of reservoirs in continental Europe

The analysis methodology used for calculating bottleneck costs and proposing grid upgrades has limitations related to the following aspects:

- The proposed stage 2 extensions have been limited to about 10 prioritized connections per scenario year (2015, 2020 and 2030). Thus, the bottleneck costs calculated for the whole European power system are only slightly reduced as a result of these reinforcements. The study have focused on pointing out

critical corridors, rather than aiming to develop an optimized grid structure and optimized capacities on new connections.
- Apart from the bottleneck cost (generation side), the network reinforcement costs are not considered.
- Creating realistic network reinforcement costs would be another huge effort as not only interconnectors, but also the (largely unknown) internal networks need to be considered.

Possible configurations of offshore subsea HVDC networks for offshore wind were presented in Chapter 5.
- All cables in the offshore grid are modelled as HVDC in the study, enabling efficient control of the power flow. However, a meshed offshore grid could also contain AC cables, possibly with power flow control options as described in Chapter 2.
- The study was limited to the North Sea and the Baltic Sea, mainly due to lack of knowledge about geographical locations of planned wind farms in other sea areas.
- The actual benefits of an offshore network (instead of radial feeders) need to take into account the savings in investment in onshore network reinforcements.
- The investment costs of onshore network reinforcements have not been estimated, and thus all benefits of integrated offshore subsea grids are not taken into account in this study. Especially important with this respect are internal grid upgrades in Great Britain, Netherlands and Germany.

The results of the study are still valuable, giving clear indications on the need for grid developments in the European power system, whether there will be high amounts of installed wind power or not in the next decades. Furthermore, the study has highlighted operational benefits of building an offshore grid, not only enabling offshore wind power to be transported effectively to areas with high demand, but also facilitating power trade between countries in hours with low wind power production, giving a high utilization of the offshore cables.

7 SUMMARY AND CONCLUSIONS

The main parts of this report present case studies on grid capacity upgrades and wind impact on bottlenecks in Europe using the Power System Simulation Tool (PSST). The simulation tool assumes a perfect power market and runs an optimal power flow for minimizing the total generating costs in the system for each hour of the simulated year. Model inputs include scenarios for grid development, onshore and offshore wind power capacity, load growth, conventional generation data and fuel costs.

The assumed scenarios include planned grid upgrades according to UCTE, Nordel and National Grid. Applying these, it has been shown that for low to moderate amounts of wind power in the system, wind power contributes to reducing the total bottleneck costs in the system, compared to a reference scenario were the wind power capacity is set to zero. However, as more wind power is introduced to the system, wind induced bottlenecks becomes more significant, especially when going from the 2030 Medium to the 2030 High wind power capacity scenario.

It is important to notice that, due to lack of available data, the grid model do not include capacity limitations on power lines internally in each country, except for a few exceptions such as parts of the Nordel system and parts of Germany.

A sensitivity analysis has been carried out by including internal constraints between zones in each country, which as expected, increases the bottleneck costs for all simulated scenarios. However, it cannot be concluded from the results that internal bottlenecks are more constraining for the case with wind power than for the case without wind power. In other words, internal constraints have a negative impact on the utilization of wind power, but at the same time it also hinders the substitution of expensive conventional generation with cheaper conventional generation located elsewhere.

Grid upgrades, in addition to those assumed in existing plans, have been proposed in this study by using a methodology for ranking of critical connections, based on how much the market model objective function (i.e. total generation costs) is influenced by the capacity of the connections. Thus, the methodology does not directly distinguish between grid upgrades needed specifically for wind power and grid upgrades needed for reduction of generating costs in general.

The report also presents an additional case study on offshore wind in the North Sea and the Baltic Sea using more detailed information on geographical locations and expected distribution of capacity. The benefits of building a meshed offshore grid in the North Sea is assessed using the grid model, by comparing total generating costs, bottleneck costs and amounts of discarded wind with a base case with radial connection of all offshore wind farms. This offshore grid connects several wind farm clusters to a HVDC-link with mainland connections to Norway, Denmark, Germany, Netherlands, Belgium and Great Britain. This does not in any way represent an optimized offshore grid, but simply an example on a possible offshore grid. Hence, the objective is to illustrate what impact an offshore grid can have relative to simple radial connections. It is found that with proper cable dimensioning in the offshore grid, it is possible to reduce the total bottleneck costs and total amounts of discarded wind energy remarkably compared to a base case with single radial connections of all offshore wind farms. Nevertheless, the bottleneck costs are still higher than for a case with no offshore wind. In addition to high internal constraints in Germany, connections between Belgium and Netherlands and Belgium and France are highly congested in the simulations with high amounts of offshore wind. As an alternative to further reinforcements on mainland connections in these areas one should consider building a stronger offshore grid than proposed in the simulation case study. Actual suggestion for such an extended ("optimized") offshore grid is out of scope of this study.

Results are generally in line with other studies on wind and grid development, i.e. grid development is required for efficient operation of the power system. The effect that modest amounts of wind actually reduces bottleneck costs simply imply that if wind is not developed, other new generation is needed instead, or this gives less efficient operation of the system. Results must generally be interpreted taking into account for model assumptions:

- perfect market model
- no costs/losses in transmission
- no start/stop costs
- no capacity limitations on lines within a country
- no power reserve requirements

These simplifications have been necessary for achieving reasonable computing time, and also simply due to lack of detailed data. A perfect match with more detailed country-by-country studies can thus not be expected. For further studies using the PSST tool an important task would be to incorporate internal grid constraints in a higher degree that was possible in this study. Further developments of the tool should include the already mentioned aspects (transmission losses, start/stop, reserves) and also improved method for handling Net Transfer Capacities within countries and handling of balancing power due to wind power uncertainty.

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APPENDIX 1 – GRID EXTENSIONS AND BOTTLENECK COSTS [9]

Table 16. Year 2015 Stage 2 reinforcements.

Type	From	To	From	To	Rate [MW]
Branch	E_BI 75	F_PR 531	ES-2	FR-6	330
	F_CO 404	CH-4 598	FR-3	CH-2	320
HVDC	Nordel: 3361	DK-71038	SE-2	DK	360
	Nordel: 5604	DK-11032	NO-1	DK	350
	NL-1 607	Nordel: 5605	NL	NO-1	700
	FROM1248	Nordel: 3300	PL-X	SE-1	600
	FROM1249	Nordel: 3300	DE-X	SE-1	600
	FROM1249	Nordel: 8501	DE-X	DK-E	550
	TOGB1250	GB: 6	FR-X	GB	2000
	FROM1252	FROM_ITA	IT-X	GR-X	500

Table 17. Year 2020 Stage 1 reinforcements.

Type	From	To	From	To	Rate [MW]
Branch	D-13 780	D-19 786	DE-1	DE-1	343
	D-19 786	PL-21101	DE-1	PL-1	392
	D_CO 795	D_DI 807	DE-2	DE-2	1382
	D_DI 807	D-44 811	DE-2	DE-2	1382
	D-41 808	D-13 780	DE-1	DE-1	408
	D-56 823	D-76 843	DE-5	DE-5	1698
	D-88 855	D-76 843	DE-5	DE-5	1698
	D-10 871	D-88 855	DE-5	DE-5	1698

Table 18. Year 2020 Stage 2 reinforcements.

Type	From	To	From	To	Rate [MW]
Branch	Nordel: 5300	Nordel: 5301	NO-1	NO-1	1000
	F-60 275	F-67 282	FR-1	FR-1	1000
	F-23 443	VENA 684	FR-4	IT-1	956
	B_ZA 534	NL_G 624	BE	NL	1476
	CH_L 559	E_TI 990	CH-1	DE-6	1131
	CH-3 593	BULI 651	CH-2	IT-1	1510
	D-16 783	D-18 785	DE-2	DE-2	312
	D_CO 795	D_DI 807	DE-2	DE-2	1382
	D-77 844	D-83 850	DE-1	DE-1	1659
	D-19 956	D-23 994	DE-4	DE-4	301
HVDC	Nordel: 6500	Nordel: 6100	NO-2	NO-1	1000
	DK-71038	Nordel: 8501	DK	DK-E	600

[9] See TradeWind WP3 report [2] for Nordel bus numbering and the PowerWorld grid model of Bialek [22] for UCTE bus numbering.

	FROM1252	FROM_ITA	IT-X	GR-X	500

Table 19. Year 2020 Stage 1 + Stage 2 reinforcements.

Type	From	To	From	To	Rate [MW]
Branch	Nordel: 5300	Nordel: 5301	NO-1	NO-1	1000
	F-60 275	F-67 282	FR-1	FR-1	1000
	F-23 443	VENA 684	FR-4	IT-1	956
	B_ZA 534	NL_G 624	BE	NL	1476
	CH_L 559	E_TI 990	CH-1	DE-6	1131
	CH-3 593	BULI 651	CH-2	IT-1	1510
	D-13 780	D-19 786	DE-1	DE-1	343
	D-16 783	D-18 785	DE-2	DE-2	312
	D-19 786	PL-21101	DE-1	PL-1	392
	D_CO 795	D_DI 807	DE-2	DE-2	2764
	D_DI 807	D-44 811	DE-2	DE-2	1382
	D-41 808	D-13 780	DE-1	DE-1	408
	D-56 823	D-76 843	DE-5	DE-5	1698
	D-77 844	D-83 850	DE-1	DE-1	1659
	D-88 855	D-76 843	DE-5	DE-5	1698
	D-10 871	D-88 855	DE-5	DE-5	1698
	D-19 956	D-23 994	DE-4	DE-4	301
HVDC	Nordel: 6500	Nordel: 6100	NO-2	NO-1	1000
	DK-71038	Nordel: 8501	DK	DK-E	600
	FROM1252	FROM_ITA	IT-X	GR-X	500

Table 20. Year 2030 Stage 1 reinforcements.

Type	From	To	From	To	Rate [MW]
Branch	E_BI 75	F_PR 531	ES-2	FR-6	330
	F_CO 404	CH-4 598	FR-3	CH-2	320
	B_ZA 534	NL_G 624	BE	NL	1476
	NL_M 627	B_15 547	NL	BE	1270
	D-41 808	D-13 780	DE-1	DE-1	408
	D-10 875	D-10 868	DE-5	DE-5	1698
	D-11 879	D-11 886	DE-3	DE-3	1659
	D-15 919	D-15 925	DE-4	DE-4	1790
	D-19 956	D-23 994	DE-4	DE-4	301
HVDC	NL-1 607	Nordel: 5605	NL	NO-1	700
	TOGB1250	GB: 6	FR-X	GB	2000
	GB: 2	IE: 7	GB	IE	1000

Table 21. Year 2020 Stage 2 reinforcements.

Type	From	To	From	To	Rate [MW]
Branch	Nordel: 5102	Nordel: 5301	NO-1	NO-1	1000
	F_CO 404	CH-4 598	FR-3	CH-2	640

	CH-2 558	E_TI 990	CH-1	DE-6	1158
	CH-3 588	CISL 666	CH-2	IT-1	514
	D-16 783	D-18 785	DE-2	DE-2	312
	D-20 787	D-49 816	DE-2	DE-3	1369
	D_CO 795	D_DI 807	DE-2	DE-2	1382
	D_DI 807	D-44 811	DE-2	DE-2	1382
	D-77 844	D-83 850	DE-1	DE-1	1659
	A_ST1004	D-18 951	AT-1	DE-4	602
HVDC	F-21 423	LEYN 678	FR-4	IT-1	1000
	FANO 703	CRT-1236	IT-2	HR	1000
	GB: 5	Nordel: 6000	GB	NO-1	2000

Table 22. Year 2020 Stage 1 + Stage 2 reinforcements.

Type	From	To	From	To	Rate [MW]
Branch	Nordel: 5102	Nordel: 5301	NO-1	NO-1	1000
	F_CO 404	CH-4 598	FR-3	CH-2	640
	CH-2 558	E_TI 990	CH-1	DE-6	1158
	CH-3 588	CISL 666	CH-2	IT-1	514
	NL_M 627	B_15 547	NL	BE	1270
	D-16 783	D-18 785	DE-2	DE-2	312
	D-20 787	D-49 816	DE-2	DE-3	1369
	D_CO 795	D_DI 807	DE-2	DE-2	1382
	D_DI 807	D-44 811	DE-2	DE-2	1382
	D-41 808	D-13 780	DE-1	DE-1	408
	D-77 844	D-83 850	DE-1	DE-1	1659
	D-10 875	D-10 868	DE-5	DE-5	1698
	D-11 879	D-11 886	DE-3	DE-3	1659
	D-15 919	D-15 925	DE-4	DE-4	1790
	A_ST1004	D-18 951	AT-1	DE-4	602
HVDC	F-21 423	LEYN 678	FR-4	IT-1	1000
	FANO 703	CRT-1236	IT-2	HR	1000
	GB: 2	IE: 7	GB	IE	1000
	GB: 5	Nordel: 6000	GB	NO-1	2000

Table 23. Year 2030 Stage 3 reinforcements.

Type	From	To	From	To	Rate [MW]
Branch	Nordel: 5600	Nordel: 5603	NO-1	NO-1	1210
	F_MA 356	CH_B 566	FR-3	CH-1	1046
	B_ZA 534	NL_G 624	BE	NL	1476
	CH-3 588	CISL 666	CH-2	IT-1	514
	D_CO 795	D_DI 807	DE-2	DE-2	2764
	D_GR 834	D-56 823	DE-5	DE-5	1698
HVDC	FROM1252	FROM_ITA	IT-X	GR-X	500
	F-21 423	LEYN 678	FR-4	IT-1	1000
	Nordel: 5604	D-24 791	NO-1	DE-2	1000

Table 24 through Table 26 shows the 10 largest sensitivities based on actual branch connections (Table 24), HVDC connections (Table 25) and NTC sum area restrictions (Table 26).

Table 24. Year 2015 sensitivities for flow on specific branches. Constrained branches internally in a zone are marked with grey color.

Br-id	Bus		Zone		Area		€/MW
1	F_CO 404	CH-4 598	FR-3	CH-2	FR	CH	485012
2	E_BI 75	F_PR 531	ES-2	FR-6	ES	FR	342176
3	D_CO 795	D_DI 807	DE-2	DE-2	DE	DE	255286
4	Nordel: 5300	Nordel: 5301	NO-1	NO-1	NO	NO	244343
5	F-23 443	VENA 684	FR-4	IT-1	FR	IT	230488
6	D-19 956	D-23 994	DE-4	DE-4	DE	DE	208228
7	F-60 275	F-67 282	FR-1	FR-1	FR	FR	196192
8	D-16 783	D-18 785	DE-2	DE-2	DE	DE	191076
9	B_AU 554	F_MO 241	BE	FR-3	BE	FR	124758
10	CRT-1241	CRT-1228	HR	HR	HR	HR	117116

The two previous tables have identical sensitivities for the 4 largest values between zones. This means that the specific branches shown in Table 24 are the only branches between these two zones which are constrained throughout the simulation.

Table 25. Year 2015 sensitivities for flow on HVDC connections

Bus		Zone		Area		€/MW
NL-1 607	Nordel: 5605	NL	NO-1	NL	NO	87997
Nordel: 5604	DK-11032	NO-1	DK	NO	DK	46625
TOGB1250	GB: 6	FR-X	GB	FR	GB	46491
Nordel: 3361	DK-71038	SE-2	DK	SE	DK	37000
FROM1248	Nordel: 3300	PL-X	SE-1	PL	SE	32288
FROM1252	FROM_ITA	IT-X	GR-X	IT	GR	30478
FROM1249	Nordel: 3300	DE-X	SE-1	DE	SE	26445
DK-71038	Nordel: 8501	DK	DK-E	DK	DK	23163
FROM1249	Nordel: 8501	DE-X	DK-E	DE	DK	15599
NL-1 621	GB: 8	NL	GB	NL	GB	10233

Table 26. Year 2015 sensitivities for the NTCs

Zone/Area		€/MW
AT	IT	393830
NO-2	NO-1	205089
SK	PL	117069
CZ	AT	88329
RS	MK	63060
CH	DE	62570
UA	RO	44486
BA	HR	40711
AT	DE	35224
SK	HU	32297

Table 27. Sensitivities for 2020 in flow on specific branches

Bus		Zone		Area		€/MW
D_CO 795	D_DI 807	DE-2	DE-2	DE	DE	419553
F-23 443	VENA 684	FR-4	IT-1	FR	IT	294925
Nordel: 5300	Nordel: 5301	NO-1	NO-1	NO	NO	273896
F-60 275	F-67 282	FR-1	FR-1	FR	FR	231100
D-16 783	D-18 785	DE-2	DE-2	DE	DE	181850
D-19 956	D-23 994	DE-4	DE-4	DE	DE	181778
CH-3 593	BULI 651	CH-2	IT-1	CH	IT	153934
D-77 844	D-83 850	DE-1	DE-1	DE	DE	132254
CH_L 559	E_TI 990	CH-1	DE-6	CH	DE	130186
B_ZA 534	NL_G 624	BE	NL	BE	NL	111741

Table 28. Sensitivities for 2020 in flow on HVDC connections

Bus		Zone		Area		€/MW
Nordel: 5604	D-24 791	NO-1	DE-2	NO	DE	125839
NL-1 607	Nordel: 5605	NL	NO-1	NL	NO	77987
TOGB1250	GB: 6	FR-X	GB	FR	GB	35917
FROM1252	FROM_ITA	IT-X	GR-X	IT	GR	29051
Nordel: 3361	DK-71038	SE-2	DK	SE	DK	26049
DK-71038	Nordel: 8501	DK	DK-E	DK	DK	18819
FROM1249	Nordel: 3300	DE-X	SE-1	DE	SE	10832
NL-1 621	GB: 8	NL	GB	NL	GB	10690
FROM1248	Nordel: 3300	PL-X	SE-1	PL	SE	10387
Nordel: 3001	Nordel: 7001	SE-2	FI-1	SE	SF	8477

Table 29. Sensitivities in 2020 for the NTCs

Zone/Area		€/MW
NO-2	NO-1	359007
CH	FR	116506
CH	DE	102748
SK	PL	95830
RS	MK	89185
RS	HR	73769
NL	DE	68126
CZ	AT	62447
UA	RO	56521
CZ	DE	55023

Table 30. Sensitivities for 2030 in flow on specific branches

Bus		Zone		Area		€/MW
CH-2 558	E_TI 990	CH-1	DE-6	CH	DE	1525525
A_ST1004	D-18 951	AT-1	DE-4	AT	DE	580101
CH-3 588	CISL 666	CH-2	IT-1	CH	IT	233745
D_CO 795	D_DI 807	DE-2	DE-2	DE	DE	221670
B_ZA 534	NL_G 624	BE	NL	BE	NL	187783
D-77 844	D-83 850	DE-1	DE-1	DE	DE	180997
D-20 787	D-49 816	DE-2	DE-3	DE	DE	166041
D_DI 807	D-44 811	DE-2	DE-2	DE	DE	129846

Nordel: 5102	Nordel: 5301	NO-1	NO-1	NO	NO	124383
D-16 783	D-18 785	DE-2	DE-2	DE	DE	114577

Table 31. Sensitivities for 2030 in flow on HVDC connections

Bus		Zone		Area		€/MW
FROM1252	FROM_ITA	IT-X	GR-X	IT	GR	197768
Nordel: 5604	D-24 791	NO-1	DE-2	NO	DE	102146
NL-1 607	Nordel: 5605	NL	NO-1	NL	NO	66346
TOGB1250	GB: 6	FR-X	GB	FR	GB	40914
Nordel: 3361	DK-71038	SE-2	DK	SE	DK	37056
NL-1 621	GB: 8	NL	GB	NL	GB	22447
DK-71038	Nordel: 8501	DK	DK-E	DK	DK	21588
Nordel: 6500	Nordel: 6100	NO-2	NO-1	NO	NO	19696
FROM1249	Nordel: 3300	DE-X	SE-1	DE	SE	15446
GB: 2	IE: 7	GB	IE	GB	IE	13873

Table 32. Sensitivities in 2030 for the NTC's

Zone/Area		€/MW
RS	HR	454099
CH	FR	336658
RO	HU	308142
RO	BG	257674
CH	DE	173849
RS	MK	158430
CZ	AT	150111
UA	SK	137871
IT	SI	126188
SK	PL	117754
NO-2	NO-1	103937
BA	HR	91810
NL	DE	90979

Table 33. Bottleneck cost in 2015

Scenario (stage # reinforcements)	1	2
Simulations with wind power:		
Grid model cost [€/MWh]	31.72	31.69
Copperplate model cost [€/MWh]	31.48	31.48
Bottleneck cost [€/MWh]	0.24	0.21
Simulations without wind power:		
Grid model cost [€/MWh]	35.77	35.73
Copperplate model cost [€/MWh]	35.51	35.51
Bottleneck cost [€/MWh]	0.26	0.22
Δ bottleneck cost [€/MWh]	-0.02	-0.01
Δ bottleneck cost [€/MWh wind]	-0.21	-0.11

Table 34. Bottleneck cost in 2020

Scenario (stage # reinforcements)	1	2
Simulations with wind power:		
Grid model cost [€/MWh]	32.33	32.26
Copperplate model cost [€/MWh]	32.01	32.01
Bottleneck cost [€/MWh]	0.32	0.25

Simulations without wind power:		
Grid model cost [€/MWh]	38.27	38.16
Copperplate model cost [€/MWh]	37.87	37.87
Bottleneck cost [€/MWh]	0.40	0.29
Δ bottleneck cost [€/MWh]	-0.07	-0.04
Δ bottleneck cost [€/MWh wind]	-0.68	-0.33

Table 35. Bottleneck cost in 2030

Scenario (stage # reinforcements)	1		2		3
Wind scenario (lo, medium, hi)	M	L	M	H	M
Simulations with wind power:					
Grid model cost [€/MWh]	31.70	34.88	31.51	29.29	31.38
Copperplate model cost [€/MWh]	30.18	33.46	30.18	27.87	30.18
Bottleneck cost [€/MWh]	1.52	1.43	1.33	1.42	1.20
Simulations without wind power:					
Grid model cost [€/MWh]	41.61	41.21	41.21	41.21	41.13
Copperplate model cost [€/MWh]	39.67	39.67	39.67	39.67	39.67
Bottleneck cost [€/MWh]	1.94	1.54	1.54	1.54	1.46
Δ bottleneck cost [€/MWh]	-0.42	-0.12	-0.21	-0.13	-0.27
Δ bottleneck cost [€/MWh wind]	-2.45	-1.02	-1.21	-0.59	-1.52

Table 36. 2000 MW internal constraints

Year	2015	2020	2030
Simulations with wind power:			
Grid model cost [€/MWh]	31.96	32.49	31.93
Copperplate model cost [€/MWh]	31.48	32.01	30.18
Bottleneck cost [€/MWh]	0.49	0.48	1.75
Simulations without wind power:			
Grid model cost [€/MWh]	36.00	38.44	41.73
Copperplate model cost [€/MWh]	35.51	37.87	39.67
Bottleneck cost [€/MWh]	0.49	0.56	2.06
Δ bottleneck cost [€/MWh]	-0.00	-0.09	-0.30
Δ bottleneck cost [€/MWh wind]	-0.02	-0.77	-1.74

Table 37. Infinite internal constraints

Year	2015	2020	2030
Simulations with wind power:			
Grid model cost [€/MWh]	31.69	32.26	31.51
Copperplate model cost [€/MWh]	31.48	32.01	30.18
Bottleneck cost [€/MWh]	0.21	0.25	1.33
Simulations without wind power:			
Grid model cost [€/MWh]	35.73	38.16	41.21
Copperplate model cost [€/MWh]	35.51	37.87	39.67
Bottleneck cost [€/MWh]	0.22	0.29	1.54
Δ bottleneck cost [€/MWh]	-0.01	-0.04	-0.21
Δ bottleneck cost [€/MWh wind]	-0.11	-0.33	-1.21

APPENDIX 2 – INTERNAL BRANCH CONSTRAINTS

Table 38. Internal branch connections with constraints. See TradeWind WP3 report [2] for Nordel bus numbering and the PowerWorld grid model of Bialek [14] for UCTE bus numbering.

From	To	MVA	From	To	MVA
Nordel: 3244	Nordel: 3245	500	D-55 822	D-30 797	1698
Nordel: 3701	Nordel: 3249	300	D_DI 807	D-44 811	1382
Nordel: 5102	Nordel: 5100	2000	D-49 816	D-54 821	1698
Nordel: 5101	Nordel: 5501	1732	D-51 818	D-55 822	1790
Nordel: 5102	Nordel: 5301	1000	D-52 819	D-58 825	1343
Nordel: 5102	Nordel: 6001	2065	D-54 821	D-71 838	1790
Nordel: 5103	Nordel: 5301	1436	D-64 831	D-55 822	1790
Nordel: 5300	Nordel: 5301	1000	D_GR 834	D-56 823	1698
Nordel: 5300	Nordel: 6100	774	D-56 823	D-76 843	1698
Nordel: 5400	Nordel: 5401	1000	D-90 857	D-74 841	1698
Nordel: 5400	Nordel: 6100	850	D-88 855	D-76 843	1698
Nordel: 5401	Nordel: 5501	2065	D-77 844	D-83 850	1659
Nordel: 5401	Nordel: 5602	2957	D-92 859	D-82 849	1659
Nordel: 5401	Nordel: 6001	2065	D-82 849	D-11 880	1659
Nordel: 5400	Nordel: 6001	2515	D-10 871	D-88 855	1698
Nordel: 5500	Nordel: 5501	500	D-11 881	D-92 859	1659
Nordel: 5500	Nordel: 5603	1472	D-10 875	D-10 868	1698
Nordel: 5600	Nordel: 5601	1000	D-11 879	D-11 886	1659
Nordel: 5600	Nordel: 5603	1210	D-12 896	D-11 880	1698
Nordel: 5601	Nordel: 6001	2515	D_RO 895	D-13 903	1580
Nordel: 5603	Nordel: 5602	1000	D-12 896	D-14 909	1659
Nordel: 6000	Nordel: 6001	1000	D-15 919	D-15 925	1790
Nordel: 6700	Nordel: 6701	1000	D-22 992	D-16 927	1150
F-60 275	F-67 282	1000	D-19 956	D-23 994	301
B-5 538	B_ME 556	1320	D-21 977	D_OB 993	762
CH-4 603	CH_R 601	320	E-21 980	E-21 978	1580
RAGU 766	PRIO 764	1000	E-21 980	D_EN 989	1580
CHIA 765	RAGU 766	1000	A-4 999	A-361031	458
D-12 779	D-20 787	1316	A_ST1004	A-351030	460
D-13 780	D-19 786	343	A-211016	A_WE1018	1000
D-41 808	D-13 780	408	CRT-1241	CRT-1228	297
D-16 783	D-18 785	312	CRT-1241	CRT-1229	1246
D-20 787	D-49 816	1369	H-121181	FROM1245	1500
D_CO 795	D_DI 807	1382			

APPENDIX 3 – OFFSHORE WIND FARMS

Table 39. List of offshore wind projects (EWEA collection).

Country	Project name	MW	Year
Belgium	Thornton Bank I	120	2009
Belgium	Thornton Bank II	180	2011
Belgium	Bligh Bank	330	2012
Belgium	Bank zonder naam	216	2015
Belgium	Unnamed I	500	2020
Belgium	Unnamed III	500	2020
Belgium	Unnamed VI	500	2020
Belgium	Unnamed II	500	2030
Belgium	Unnamed IV	500	2030
Belgium	Unnamed V	500	2030
Denmark	Vindeby	4.95	1991
Denmark	Tunø Knob	5	1995
Denmark	Middelgrunden	40	2001
Denmark	Horns Rev I	160	2002
Denmark	Frederikshavn	10.6	2003
Denmark	Nysted I	165.6	2003
Denmark	Rønland	17.2	2003
Denmark	Samsø	23	2003
Denmark	Horns Rev II	200	2009
Denmark	Nysted II	200	2010
Denmark	Nysted II-test	15	2010
Denmark	Kriegers Flak III	455	2013
Denmark	A - Horns Rev	200	
Denmark	B - Horns Rev	200	
Denmark	C - Horns Rev	200	
Denmark	F - Ringkøbing	200	
Denmark	K - Jammerbugt	200	
Denmark	L - Jammerbugt	200	
Denmark	M - Jammerbugt	200	
Denmark	Q - Store Middelgrund	200	
Denmark	V - Rønne Banke	200	
Finland	Korsnõs	400	
Finland	Kristiinankaupunki-Narpi÷	300	
Finland	Pori	50	
Finland	Suurhiekka	400	
Germany - Baltic Sea	Baltic 1 (Rostock)	53.5	2009
Germany - Baltic Sea	Sky 2000	150	2012
Germany - Baltic Sea	Arkona-Becken Südost phase 1	400	2013
Germany - Baltic Sea	Kriegers Flak I phase 2	145	2013
Germany - Baltic Sea	Ventotec Ost 2 phase 1	150	2013
Germany - Baltic Sea	Beltsee	415	2014
Germany - Baltic Sea	Ventotec Ost 2 phase 2	450	2015
Germany - Baltic Sea	Arkona-Becken Südost phase 2	605	2016
Germany - North Sea	Borkum West phase 1	60	2008
Germany - North Sea	Borkum Riffgrund phase 1	231	2009
Germany - North Sea	Butendiek	240	2009
Germany - North Sea	Borkum Riffgrund West phase 1	280	2010
Germany - North Sea	Nördlicher Grund phase 1	400	2010
Germany - North Sea	Kriegers Flak I phase 1	183.6	2011
Germany - North Sea	Nordergründe	125	2011
Germany - North Sea	North Sea Windpower phase 1	216	2011
Germany - North Sea	Sandbank 24 phase 1	400	2011
Germany - North Sea	Borkum Riffgat	220	2012
Germany - North Sea	Globaltech 1 phase 1	400	2012
Germany - North Sea	Godewind phase 1	400	2012
Germany - North Sea	Hochsee Windpark Nordsee phase 1	400	2012
Germany - North Sea	Nordsee Ost phase 1	400	2012
Germany - North Sea	Uthland	400	2012
Germany - North Sea	Amrumbank West	400	2013

Germany - North Sea	DanTysk phase 1	400	2013
Germany - North Sea	He Dreiht	535.5	2013
Germany - North Sea	Meerwind phase 1	200	2013
Germany - North Sea	Ventotec Nord 1 phase 1	150	2013
Germany - North Sea	Ventotec Nord 2 phase 1	150	2013
Germany - North Sea	Austerngrund	400	2014
Germany - North Sea	BARD Offshore 1 phase 1	400	2014
Germany - North Sea	Deutsche Bucht	400	2014
Germany - North Sea	Borkum Riffgrund phase 2	515	2015
Germany - North Sea	Borkum West phase 2	980	2015
Germany - North Sea	Borkum Riffgrund West phase 2	1520	2016
Germany - North Sea	DanTysk phase 2	1100	2016
Germany - North Sea	Nordsee Ost phase 2	850	2016
Germany - North Sea	Ventotec Nord 1 phase 2	450	2016
Germany - North Sea	Ventotec Nord 2 phase 2	450	2016
Germany - North Sea	Godewind phase 2	720	2017
Germany - North Sea	Meerwind phase 2	950	2018
Germany - North Sea	North Sea Windpower phase 2	1010	2018
Germany - North Sea	Nördlicher Grund phase 2	1610	2018
Germany - North Sea	Globaltech 1 phase 2	1200	2019
Germany - North Sea	Hochsee Windpark Nordsee phase 2	2155	2019
Germany - North Sea	Sandbank 24 phase 2	4500	2019
Germany - North Sea	BARD Offshore 1 phase 2	1200	2020
Great Britain	Blyth Offshore	4	2000
Great Britain	North Hoyle	60	2003
Great Britain	Scroby Sands	60	2004
Great Britain	Kentish flats	90	2005
Great Britain	Barrow	90	2006
Great Britain	Beatrice demo	10	2007
Great Britain	Burbo	90	2007
Great Britain	Inner Dowsing	97.2	2008
Great Britain	Lynne	97.2	2008
Great Britain	Gunfleet Sands I	108	2009
Great Britain	Lincs	250	2009
Great Britain	Rhyl Flats	99	2009
Great Britain	Solway firth	180	2009
Great Britain	Thanet	300	2009
Great Britain	Cromer	108	2010
Great Britain	Greater Gabbard I	300	2010
Great Britain	Gunfleet Sands II	64	2010
Great Britain	London Array I	270	2010
Great Britain	Teeside/Redcar	90	2010
Great Britain	Walney I	151	2010
Great Britain	Humber Gateway	300	2011
Great Britain	Ormonde	108	2011
Great Britain	Sheringham Shoal	315	2011
Great Britain	Aberdeen Harbour	115	2012
Great Britain	Docking Shoal	500	2012
Great Britain	Greater Gabbard II	200	2012
Great Britain	London Array II	200	2012
Great Britain	London Array III	330	2012
Great Britain	London Array IV	200	2012
Great Britain	Race ranck	500	2012
Great Britain	Shell flat	324	2012
Great Britain	West Duddon	500	2012
Great Britain	Dudgeon East	300	2013
Great Britain	Walney II	299	2013
Great Britain	Gwynt y Mor	750	2014
Great Britain	Westermost Rough	240	2014
Great Britain	Beatrice	990	2016
Great Britain	Triton Knoll	1200	2017
Great Britain	Round 3	1000	
Great Britain	Round 3	1000	
Great Britain	Round 3	1000	
Great Britain	Round 3	1000	

Great Britain	Round 3	1000	
Great Britain	Round 3	1000	
Great Britain	Round 3	1000	
Great Britain	Round 3	1000	
Great Britain	Round 3	1000	
Great Britain	Round 3	1000	
Great Britain	Round 3	1000	
Great Britain	Round 3	1000	
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Great Britain	Round 3	1000	
Great Britain	Round 3	1000	
Great Britain	Round 3	1000	
Great Britain	Round 3	1000	
Great Britain	Round 3	1000	
Great Britain	Round 3	1000	
Great Britain	Round 3	1000	
Great Britain	Round 3	1000	
Great Britain	Scarweather Sands	108	
Netherlands	BARD Offshore NL1	280	
Netherlands	Breeveertien	210	
Netherlands	Brown Ridge Oost	270	
Netherlands	Bruine Bank	550	
Netherlands	Callantsoog-Noord	328	
Netherlands	Den Helder 1	500	
Netherlands	Den Helder I	695	
Netherlands	Den Helder Noord	450	
Netherlands	Den Haag II	480	
Netherlands	Den Haag Noord	285	
Netherlands	Eurogeul Noord	275	
Netherlands	Favorius	129	
Netherlands	GWS Offshore NL1	280	
Netherlands	Helmveld	425	
Netherlands	Hoek van Holland 3	500	
Netherlands	Hopper	400	
Netherlands	Ijmuiden	246	
Netherlands	IJmuiden 1	500	
Netherlands	Katwijk Buiten	325	
Netherlands	Maas West Buiten	175	
Netherlands	Noord Hinder 1	560	
Netherlands	Okeanos Noord	38	
Netherlands	Oost Friesland	500	
Netherlands	Osters Bank 1	500	
Netherlands	Osters Bank 3	500	
Netherlands	P15-WP	219	
Netherlands	Q10	151	
Netherlands	Q7-West	245	
Netherlands	Riffgrond	400	
Netherlands	Rijnveld Noord	60	
Netherlands	Rijnveld West	144	
Netherlands	Scheveningen 3	500	
Netherlands	Schaar	328	
Netherlands	West Rijn	180	
Netherlands	Wijk aan Zee	200	
Netherlands	WindNed Noord	156	
Norway	Fosen II	300	2015
Norway	Havsul I	350	2015
Norway	Stadtvind	920	2020
Norway	Stadtvind	80	2020
Norway	Sørlige Nordsjøen	20	2020
Norway	Utsira	300	2020
Norway	Fosen III	300	2030
Norway	Havsul II	800	2030
Norway	Sørlige Nordsjøen	970	2030

Norway	Unnamed 1	800	2030
Norway	Unnamed 2	730	2030
Norway	Unnamed 3*	1000	2030
Norway	Unnamed 4*	730	2030
Sweden	Bockstigen	2.5	1998
Sweden	Utgrunden I	10	2001
Sweden	Yttre Stengrund	10	2002
Sweden	Lillgrund	110	2007
Sweden	Gässlingegrund	30	2009
Sweden	Skottarevet	150	2011
Sweden	Trolleboda	150	2011
Sweden	Hakefjorden	51	2012
Sweden	Kårehamn	51	2012
Sweden	Kriegers Flak	640	2015
Sweden	Taggen	300	2015
Sweden	Stora Middelgrund	864	2016
Sweden	Storgrundet	265	2016
Sweden	Klocktärnan	660	2017
Sweden	Finngrunden	1050	2018
Sweden	Södra Midsjöbanken	1000	2019

Table 40. Close offshore wind clusters in the North Sea and the Baltic Sea

Cluster name	Lon	Lat	Onshore bus	2030 H (MW)
DE Geofree (Baltic)	11.3 E	54.3 N	D-11	25
DE Nordergrunde (N sea)	8.0 E	53.8 N	D-22	125
NL South (close)	3.1 E	51.4 N	NL_Borss	727
NL North (close)	6.0 E	53.4 N	NL-3	1500
England E (close)	1.0 E	53.2 N	GB: 6	3427.4
England NE (close)	-1.0 E	54.7 N	GB: 3	634
England NW (close)	-3.4 E	54.1 N	GB: 3	2471
England NW far	-3.9 E	54.1 N	GB: 3	3000
England S (close)	-3.1 E	50.5 N	GB: 6	2000
England SE (close)	1.2 E	51.7 N	GB: 6	2062
Scotland E (close)	-2.3 E	56.5 N	GB: 2	1000
Scotland NE (close)	-3.1 E	58.1 N	GB: 5	1030
Scotland SW (close)	-3.7 E	54.8 N	GB: 2	180
Scotland W (close)	-6.6 E	55.9 N	GB: 1	1000
Wales (close)	-3.8 E	51.5 N	GB: 6	2196
DK Nysted (close)	11.7 E	54.6 N	Nordel: 8500	380.6
DK Frederikshavn (close)	10.6 E	57.4 N	DK-1	10.6
DK Tuno Knob (close)	10.4 E	56.0 N	DK-2	5
DK Ringkobing (close)	8.2 E	56.7 N	DK-4	217.2
DK Samso (close)	10.6 E	55.7 N	DK-7	23
DK E (close)	12.7 E	55.7 N	Nordel: 8500	44.95
SE Centre (Gotland)	17.1 E	56.9 N	Nordel: 3200	74
SE North (Centre)	18.4 E	60.7 N	Nordel: 3245	2000
SE North (North)	21.9 E	65.0 N	Nordel: 3115	2000
SE Ringhals	11.5 E	57.6 N	Nordel: 3359	201
SE South (East)	14.9 E	55.9 N	Nordel: 3300	450
SE South (West)	12.7 E	55.5 N	Nordel: 3300	110
NO Fosen (close)	10.2 E	64.3 N	Nordel: 6500	600
NO Havsul (close)	6.3 E	62.8 N	Nordel: 6500	890
NO North (middle)	11.5 E	67.3 N	Nordel: 6700	1000
NO North (north)	17.5 E	70.2 N	Nordel: 6700	730

Table 41. Far offshore wind clusters in the North Sea and the Baltic sea. Distance to shore is measured as the direct line to the nearest onshore substation.

Cluster name	Distance to shore (km)	Cluster bus	Lon	Lat	Onshore bus	2030 H (MW)
DE Baltic1 (Baltic)	63	DE-O1	12.7 E	54.6 N	D-5	53.5
DE Kriegers Flak (Baltic)	114	DE-O2	13.2 E	55.0 N	D-5	328.6
DE Rostock (Balitc)	49	DE-O3	11.5 E	54.5 N	D-5	565
DE Rugen (Baltic)	83	DE-O4	14.1 E	54.8 N	D-3	1605
DE Borkum 1 (N sea)	77	DE-O5	6.8 E	54.0 N	D-27	7185
DE Borkum 2 (N sea)	155	DE-O6	6.2 E	54.4 N	D_Diele	8000
DE Borkum Riffgat (N sea)	92	DE-O7	6.4 E	53.7 N	D_Diele	220
DE Butendiek (N sea)	110	DE-O8	7.8 E	55.0 N	D-1	240
DE Helgoland 1 (N sea)	112	DE-O9	7.7 E	54.4 N	D-12	2800
DE Helgoland 2 (N sea)	193	DE-O10	6.9 E	55.1 N	D-12	8810
NL South 1 (far)	63	NL-O1	3.3 E	52.1 N	NL-15	4223
NL South 2 (far)	56	NL-O2	3.4 E	52.2 N	NL-15	2875
NL South 3 (far)	74	NL-O3	3.3 E	52.4 N	NL-15	3923
NL Mid 1 (far)	37	NL-O4	4.1 E	52.3 N	NL-11	1403
NL Mid 2 (far)	41	NL-O5	4.0 E	52.5 N	NL-11	2748
NL North (far)	102	NL-O6	5.4 E	54.0 N	NL-4	2600
England E far	81	GB-O1	2.1 E	53.3 N	GB: 6	6000
England NE far	179	GB-O2	1.5 E	54.8 N	GB: 3	8000
DK Jylland SW (N sea)	50	DK-O1	7.7 E	55.6 N	DK-8	960
DK Jylland N (N sea)	77	DK-O2	9.0 E	57.5 N	DK-1	813
DK Store Middelgrund	60	DK-O3	12.2 E	56.5 N	Nordel: 8500	200
DK Kriegers Flak (Baltic)	80	DK-O4	13.0 E	55.0 N	Nordel: 8500	455
DK Ronne Banke (Baltic)	114	DK-O5	14.2 E	54.7 N	Nordel: 3300	200
SE Kriegers Flak (Baltic)	80	SE-O1	13.3 E	54.8 N	Nordel: 3300	1971
SE Middelgrund	43	SE-O2	12.3 E	56.5 N	Nordel: 3300	2194
SE Midsjo	179	SE-O3	17.6 E	55.7 N	Nordel: 3200	2000
NO North Sea S	147	NO-O1	5.7 E	57.0 N	Nordel: 5600	990
NO North Sea M	43	NO-O2	4.6 E	59.3 N	Nordel: 6000	560
NO North Sea N	77	NO-O3	4.5 E	62.3 N	Nordel: 6100	1000
NO Norwegian sea S	110	NO-O4	7.3 E	63.8 N	Nordel: 6500	1530
BE offshore	39	BE-O1	3.0 E	51.6 N	BE-3	3800

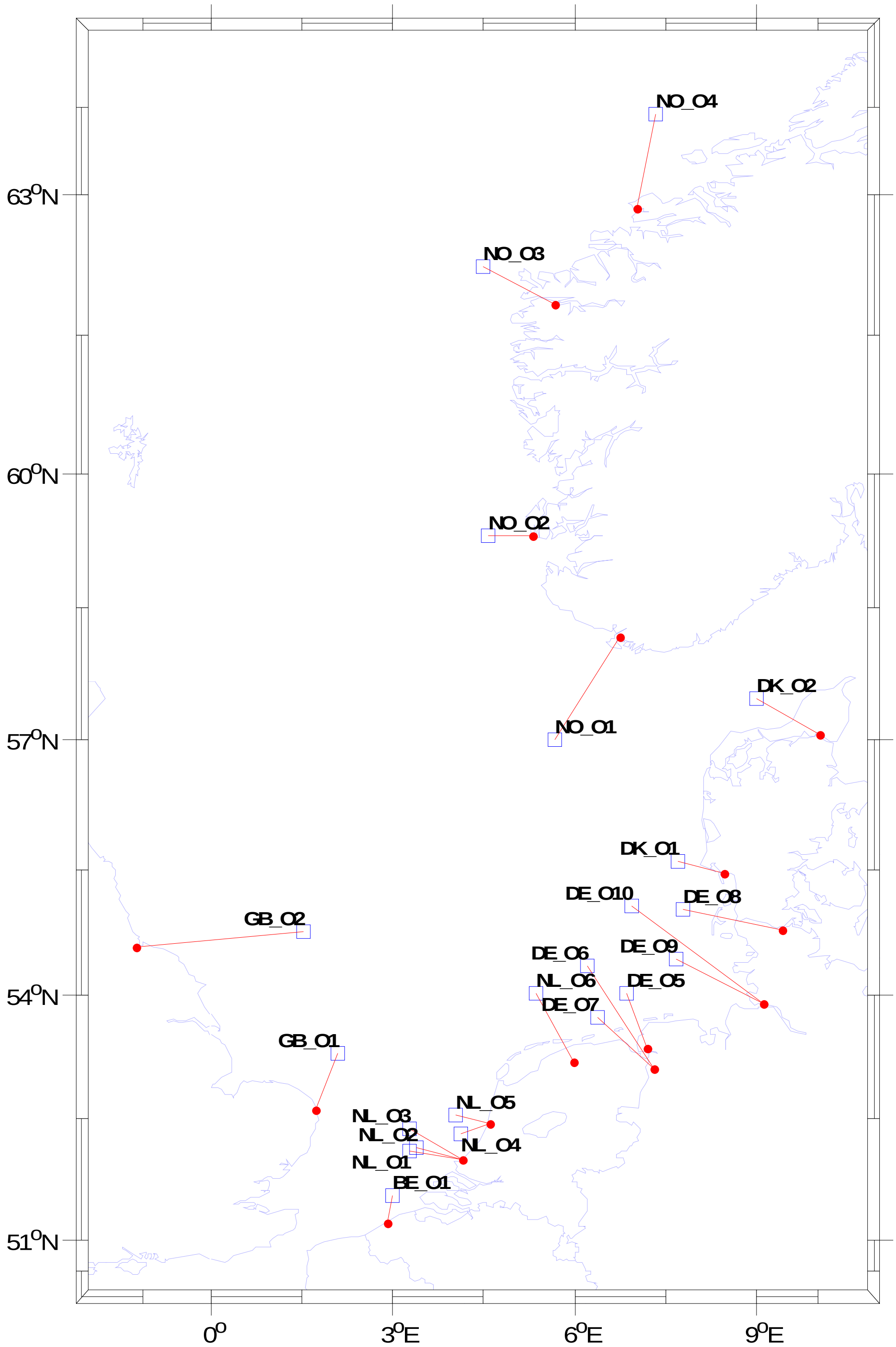

Figure 43. Far offshore wind clusters in the North Sea, shown with radial connection.

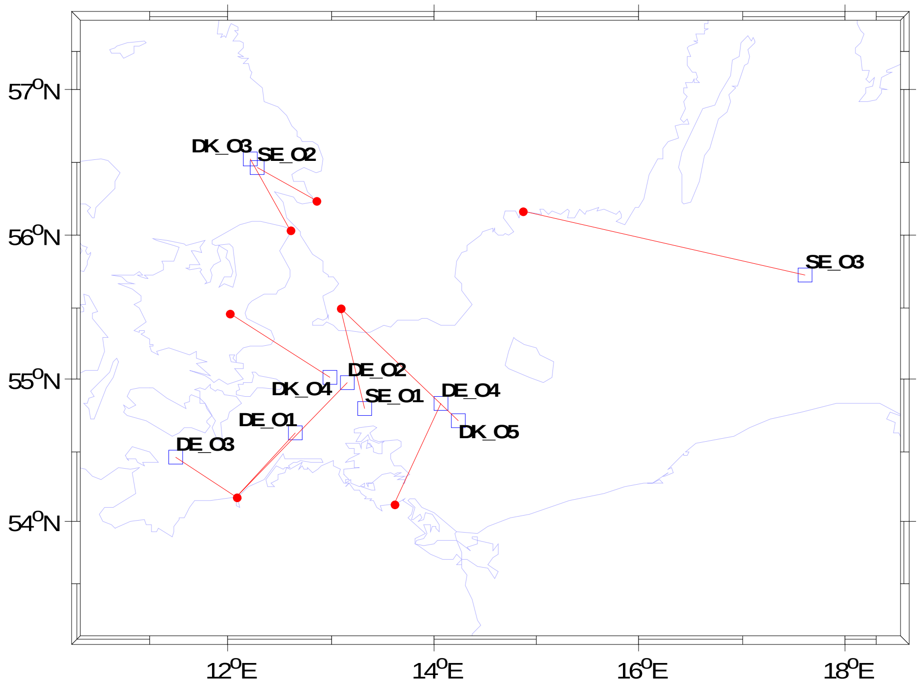

Figure 44. Far offshore wind clusters in the Baltic Sea, shown with radial connection.

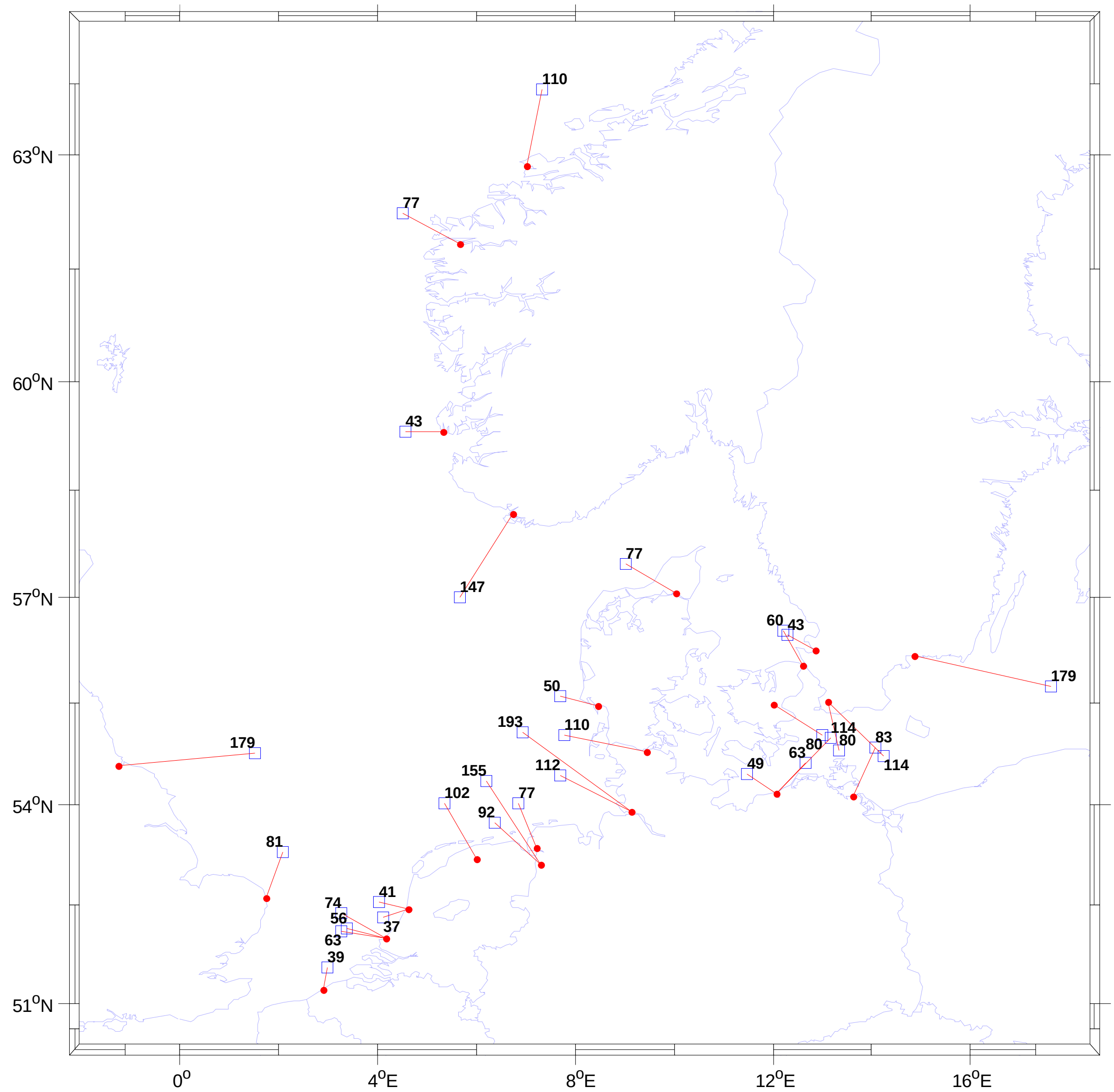

Figure 45. Far offshore wind clusters and their distance to possible mainland substations.

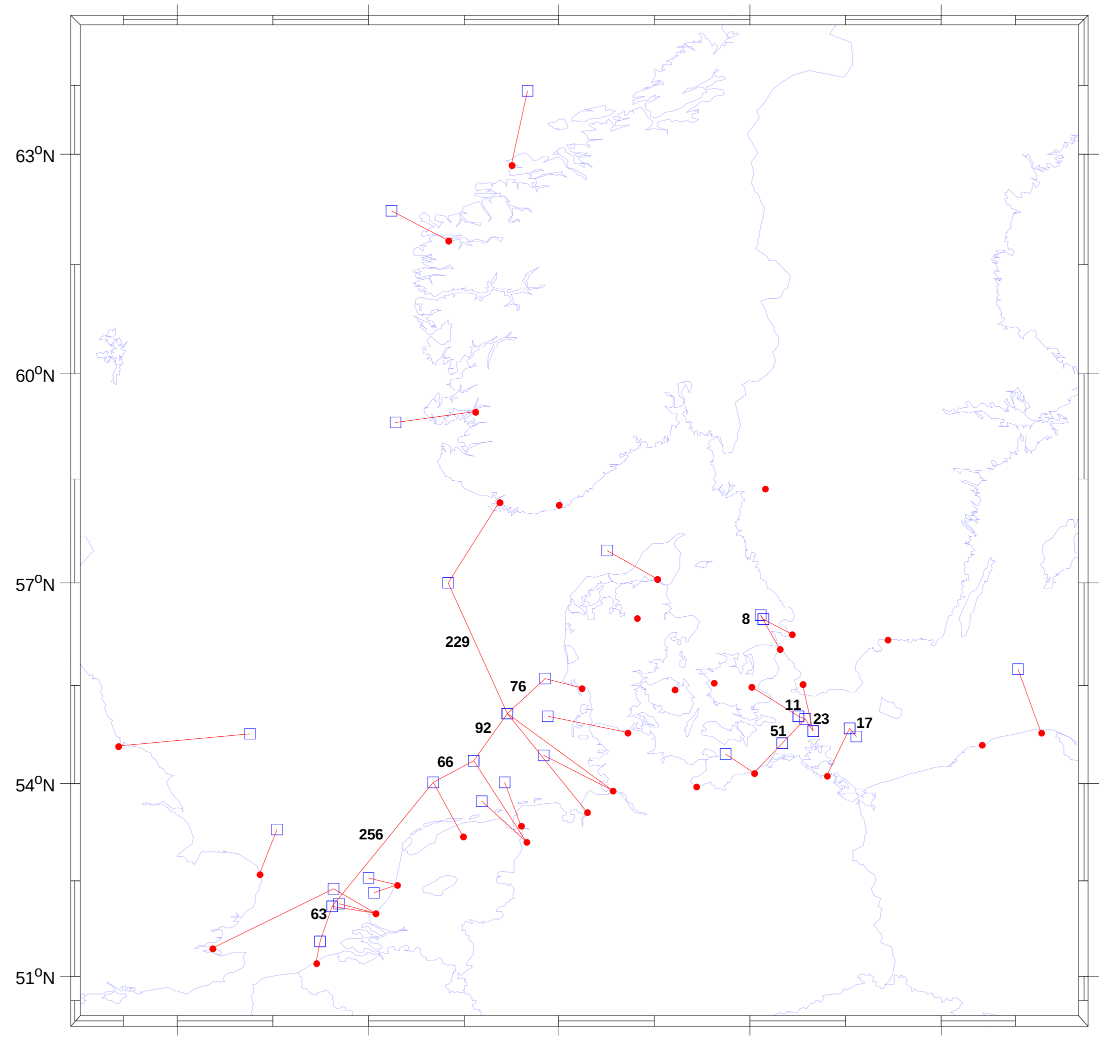

Figure 46. Length (km) of added cables in the meshed offshore grid.

APPENDIX 4 – GRID CONNECTION OF OFFSHORE WIND IN GERMANY (DENA)

Grid connection in the E.ON Netz zone – North Sea

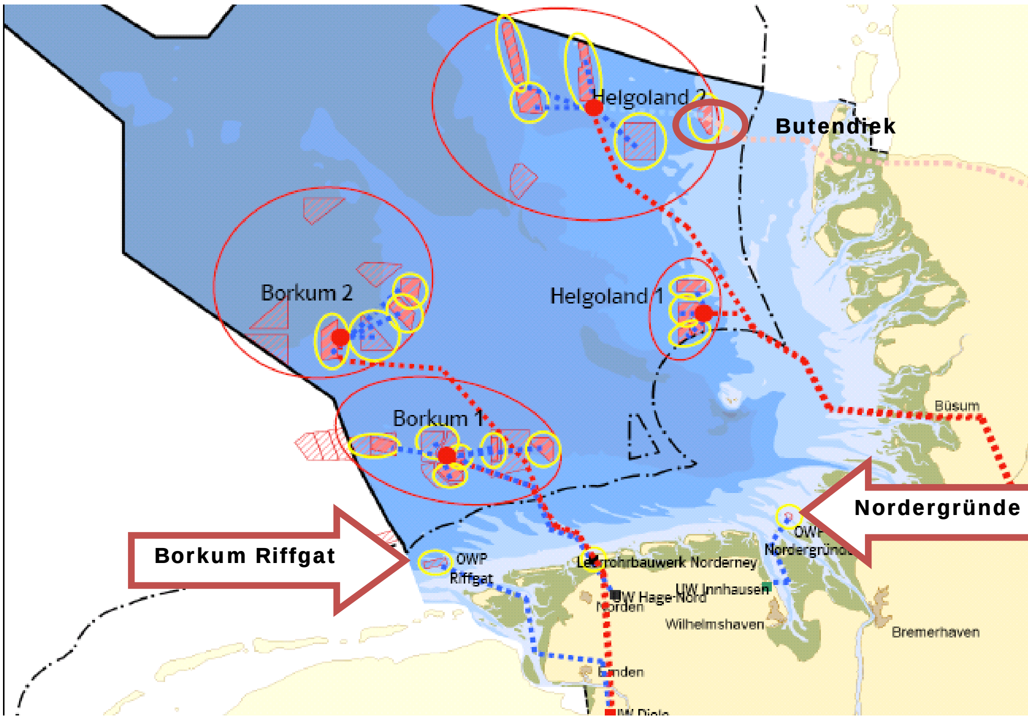

Figure 47: Clusters in the North Sea (source: E.ON Netz).

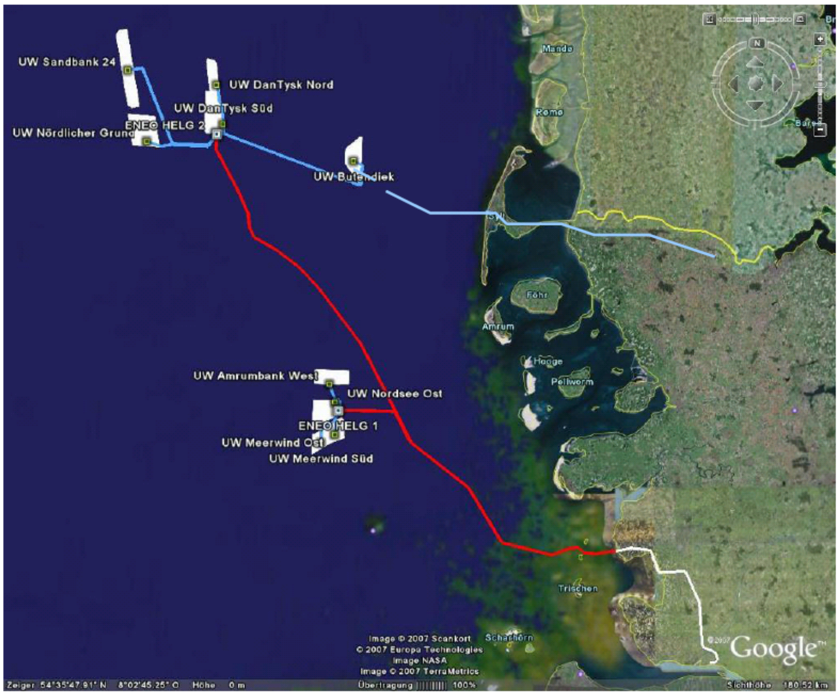

Figure 48:Cluster Helgoland I, Helgoland II and Butendiek (source: E.ON Netz).

Grid connection in the Vattenfall zone – Baltic Sea

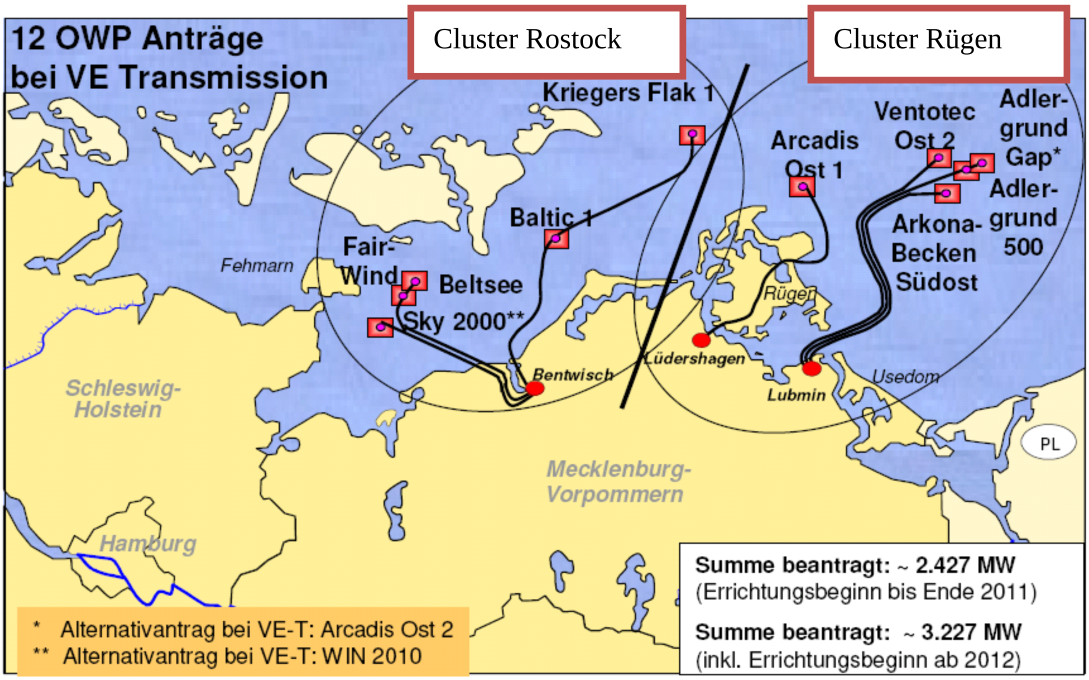

Figure 49:Clusters in the Baltic Sea. In regard to capacity the offshore wind park Arcadis Ost 1 was integrated into the Rügen cluster, but it might be connected to a different onshore connection point (source: Vattenfall Europe Transmission).

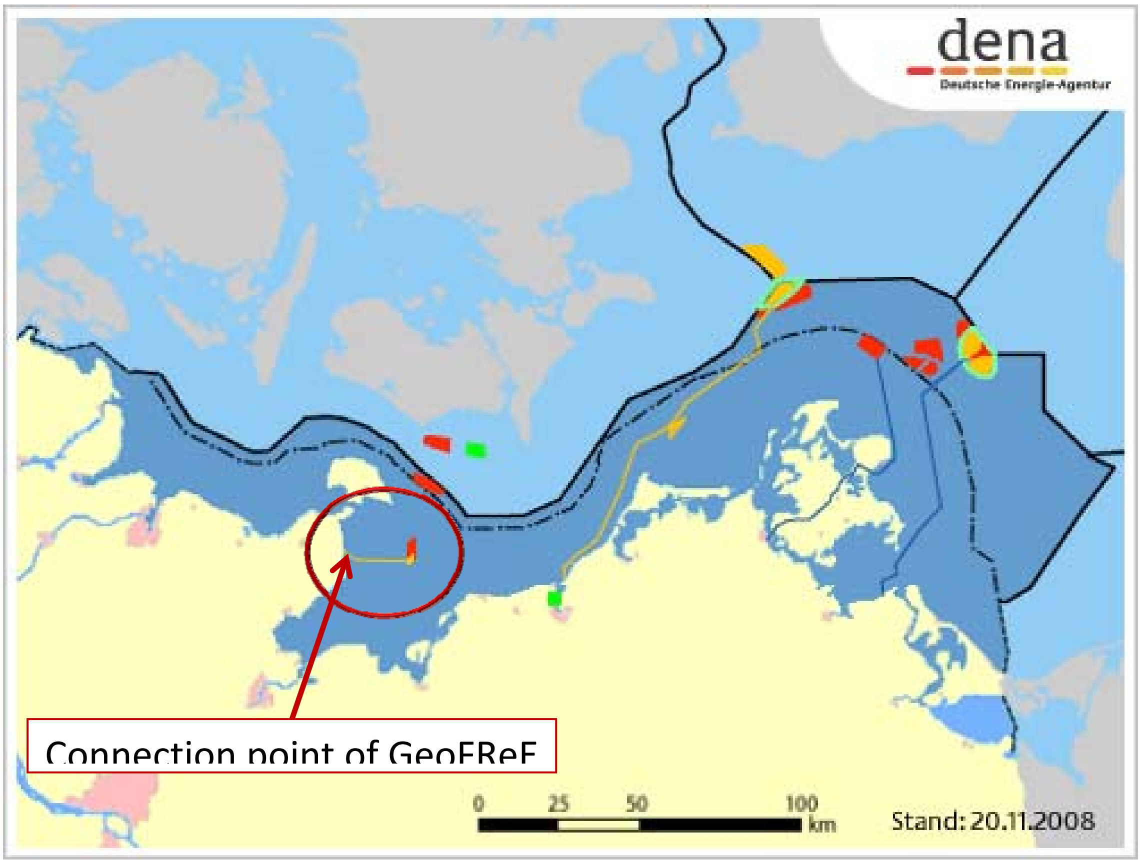

Figure 50:Connection of GeoFReE to a connection point in Schleswig-Holsten (source: dena).

Table 42. Suggested grid connection points for German offshore wind clusters.

offshore cluster	onshore substation	TradeWind node number
Butendiek	**Flensburg**	DE-1
Helgoland II	**UW Brunsbüttel**	DE-12
Helgoland II	**UW Brunsbüttel**	DE-12
Borkum I	**D_Diele / UW Hage Nord**	D27 and D_Diele
Borkum II	**Diele**	D_Diele
Borkum Riffgat	**Diele**	D_Diele
Nordergründe	**UW Innhausen**	D 22
GeoFreE	**Lübeck or Kiel/Süd**	DE-4 or DE-11
Rügen[10]	**Lubmin**	DE-3
Rostock	**Bentwisch**	DE-5

[10] The wind park Arcadis was integrated into the cluster „Rügen", but it might not be connected to the same onshore connection point. Currently the planned connection point for Arcadis is Lüdershagen (DE-2).

APPENDIX 5 - ADDITIONAL RESULTS FOR OFFSHORE GRID SCENARIOS

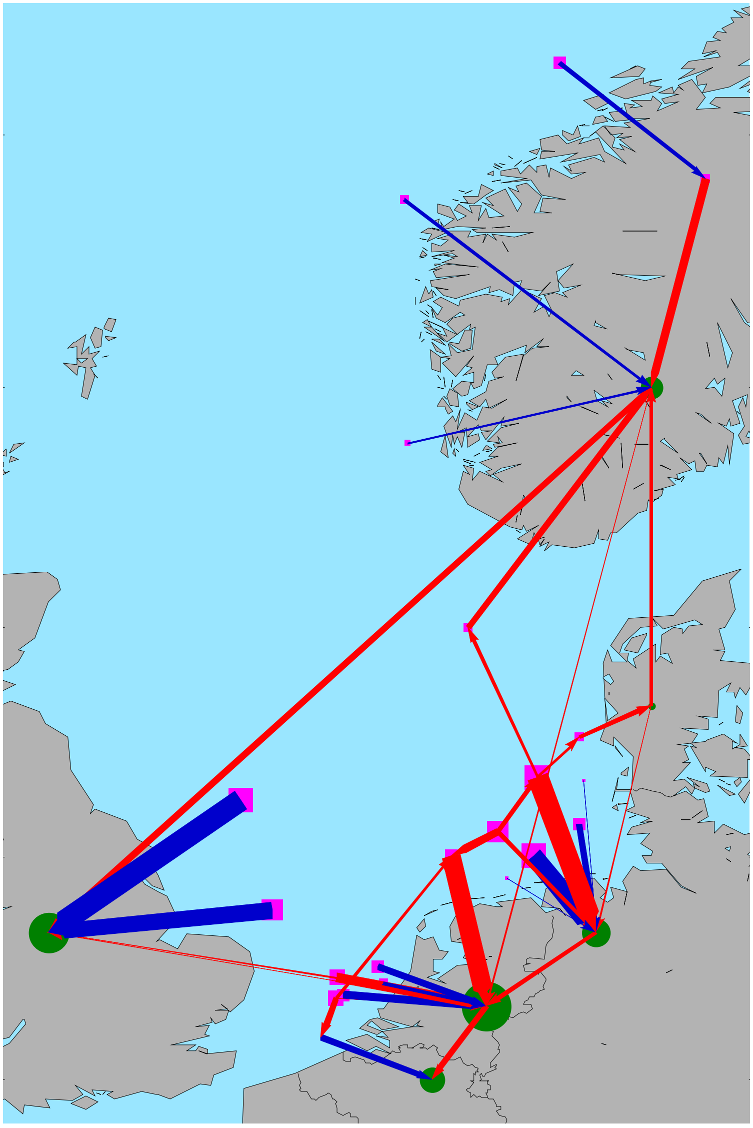

Figure 51. Energy flow in 2030, North Sea

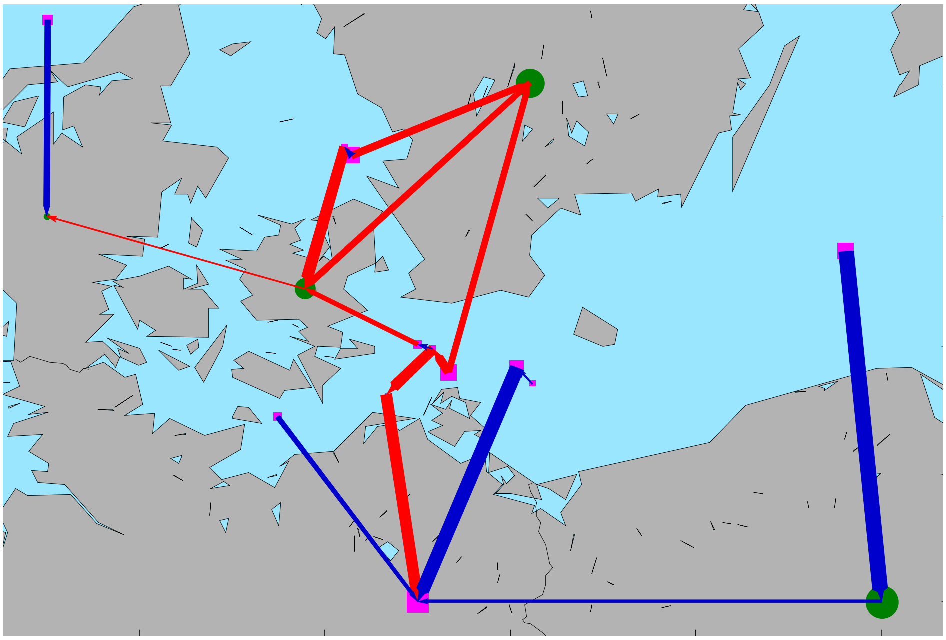

Figure 52. Energy flow in 2030, Baltic Sea

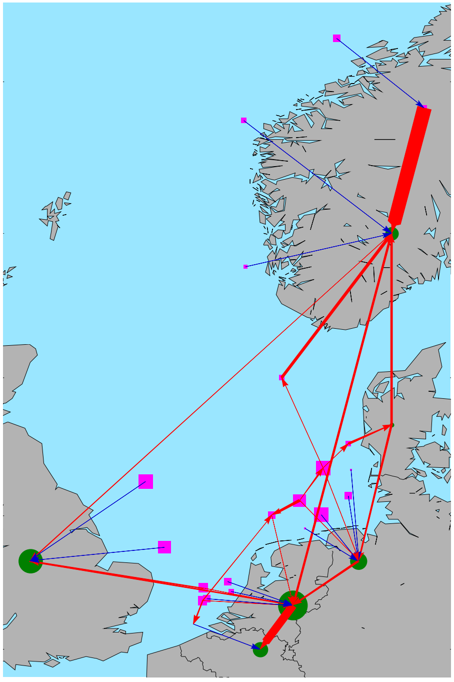

Figure 53. Sensitivities in 2030, North Sea

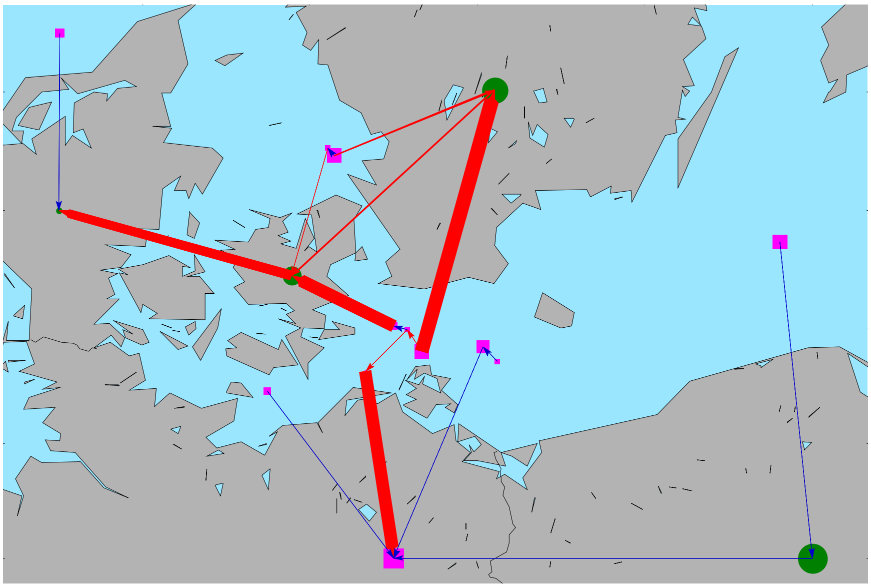

Figure 54. Sensitivities in 2030, Baltic Sea

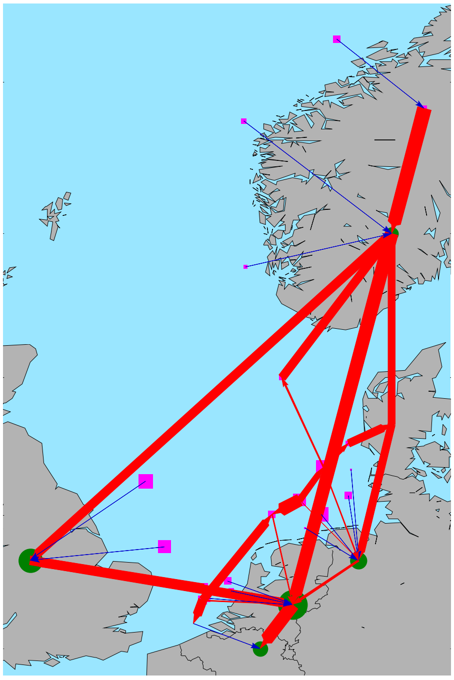

Figure 55. Hours congested in 2030, North Sea

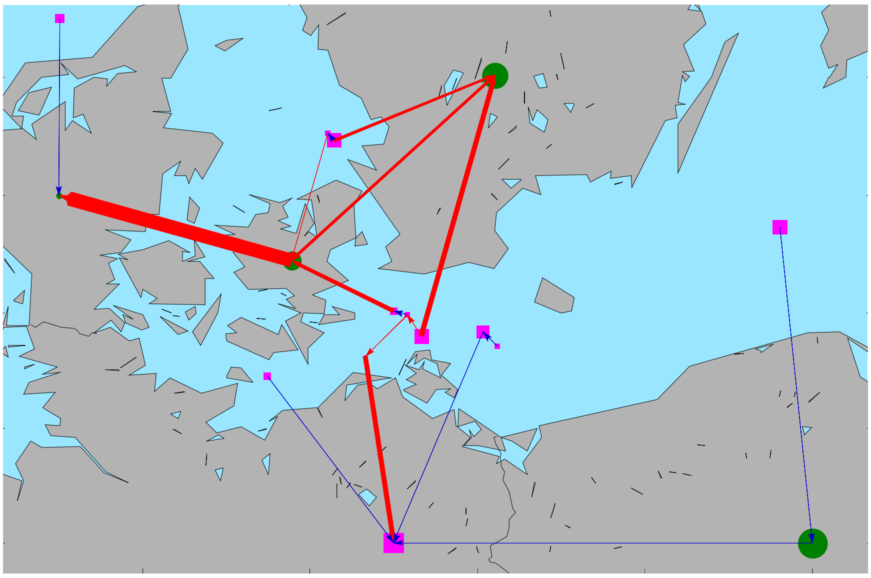

Figure 56. Hours congested in 2030, Baltic Sea

Table 43. Bottleneck cost 2030 High

Offshore grid	Radial	Meshed	
Case		1	2
Simulations with offshore wind:			
Grid model cost [€/MWh]	28.60	28.61	28.53
Copperplate model cost [€/MWh]	27.12	27.12	27.12
Bottleneck cost [€/MWh]	1.48	1.48	1.41
Simulations without offshore wind:			
Grid model cost [€/MWh]	33.94	33.94	33.94
Copperplate model cost [€/MWh]	32.60	32.60	32.60
Bottleneck cost [€/MWh]	1.34	1.34	1.34
Δ bottleneck cost [€/MWh]	0.14	0.15	0.07
Δ bottleneck cost [€/MWh wind]	0.62	0.64	0.30

Table 44. Constrained wind meshed offshore grid Case 2

Zone	Wind pot.	Wind actual	Constrained	(1-Act/Pot)
DE-1	26066	26062	4	0.01
DE-2	19653	17783	1870	9.52
DE-O1	178	165	13	7.28
DE-O10	32359	28995	3364	10.39
DE-O5	27766	27731	35	0.13
DE-O6	30916	23948	6968	22.54
DE-O7	850	790	60	7.04
DE-O9	10284	8225	2059	20.02
DK-O4	1487	1455	32	2.16
ES-1	65180	65161	19	0.03
ES-2	21800	21792	8	0.03
FR-3	16338	13552	2787	17.06
GB	152802	152767	35	0.02
HR	7713	7499	214	2.77
IE	22938	22936	2	0.01
NL	17339	17309	31	0.18

NO-1	3399	3386	14	0.41
NO-2	13707	11770	1938	14.14
NO-3	10925	10901	24	0.22
NO-O1	3853	3853	1	0.02
NO-O4	5561	5515	46	0.83
NL-O1	14722	14705	16	0.11
NL-O2	10022	9981	40	0.40
SE-O1	6443	6439	3	0.05
Tot	1069258	1049675	19583	1.83

Table 45. Constrained wind meshed offshore grid (internal 1500 case 2)

Zone	Wind pot.	Wind actual	Constrained	(1-Act/Pot)
AT-1	19713	19454	258	1.31
DE-2	19653	15992	3661	18.63
DE-6	786	784	2	0.22
DE-O1	178	164	14	7.90
DE-O10	32359	29413	2946	9.10
DE-O5	27766	27536	230	0.83
DE-O6	30916	21476	9440	30.53
DE-O7	850	815	35	4.09
DE-O9	10284	7402	2882	28.03
DK-O4	1487	1462	26	1.73
ES-1	65180	65155	25	0.04
ES-2	21800	21798	2	0.01
ES-3	24708	24701	7	0.03
FR-2	22445	21627	819	3.65
FR-3	16338	14658	1680	10.28
GB	152802	152779	23	0.02
HR	7713	7489	224	2.90
IE	22938	22936	2	0.01
NL	17339	17326	14	0.08
NO-1	3399	3386	14	0.40
NO-2	13707	11766	1941	14.16
NO-3	10925	10900	25	0.23
NO-O1	3853	3853	1	0.02
NO-O4	5561	5517	44	0.79
NL-O1	14722	14499	222	1.51
NL-O2	10022	9972	50	0.49
SE-O1	6443	6434	9	0.13
Tot	1069258	1044662	24596	2.30

Table 46. Constrained wind radial offshore grid

Zone	Wind pot.	Wind actual	Const.	(1-Act/Pot)
DE-2	19653	18959	694	3.53
DE-O10	32359	27129	5230	16.16
DE-O6	30916	21034	9881	31.96
DE-O7	850	815	35	4.15
DE-O9	10284	3524	6760	65.73
ES-1	65180	65163	17	0.03
ES-2	21800	21790	10	0.04

FR-3	16338	13584	2754	16.86
GB	152802	152778	24	0.02
HR	7713	7497	216	2.80
IE	22938	22936	2	0.01
NL	17339	17332	8	0.04
NO-1	3399	3386	13	0.39
NO-2	13707	11675	2032	14.83
NO-3	10925	10901	24	0.22
NO-O4	5561	5515	46	0.83
NL-O1	14722	13810	912	6.19
NL-O2	10022	10012	9	0.09
NL-O3	13676	13667	9	0.07
Tot	1069258	1040582	28676	2.68

Table 47. Constrained wind radial offshore grid (internal 1500)

Zone	Wind pot.	Wind actual	Const.	(1-Act/Pot)
AT-1	19713	19475	238	1.21
DE-2	19653	17514	2139	10.88
DE-6	786	784	2	0.26
DE-O10	32359	27069	5290	16.35
DE-O5	27766	27761	5	0.02
DE-O6	30916	18083	12833	41.51
DE-O7	850	745	105	12.35
DE-O9	10284	3414	6870	66.80
ES-1	65180	65154	26	0.04
ES-3	24708	24701	8	0.03
FR-2	22445	21609	837	3.73
FR-3	16338	14665	1674	10.24
GB	152802	152778	23	0.02
HR	7713	7487	226	2.92
IE	22938	22936	2	0.01
NO-1	3399	3386	13	0.38
NO-2	13707	11644	2063	15.05
NO-3	10925	10899	25	0.23
NL-O1	14722	13180	1542	10.47
NL-O2	10022	9953	69	0.68
NL-O3	13676	13674	2	0.01
Tot	1069258	1035266	33992	3.18

Cable cost assumptions

To compute the cost of a cable the following equation was used:

C = SC_cable*distance*rating + SC_conv*rating

where SC_cable is the specific cost of the cable, including laying (M€/km*MW) and SC_conv is the specific cost of rectifier/inverter equipment (M€/MW). The assumed cable parameters are given in Table 48.

Table 48. Assumed cable cost details for Oseberg oil rig study (Norwegian Water Resources and Energy Directorate) and Borkum 2[11] wind farm (ABB, VSC HVDC).

Cable	Distance [km]	Rating [MW]	Total cost [M€]	Cable inc laying [M€]	Converters [M€]	SC_cable [M€/MW*km]	SC_conv [M€/MW]
Oseberg	160	670	378	225	152	2.1e-3	0.324
Borkum2	128 (75+128)	400	300	170	130	2.1e-3	0.593

Table 49 shows all the subsea connections that are added, changed or removed in the meshed grid case. Removed cables or cables with reduced capacity are shown with negative values for capacity. Using the cost figures from Table 48, the total installation cost increase for the meshed network was found to be 3900-9000 M€ (Borkum 2 assumptions gives the highest costs). This corresponds to annual costs of 300-400 M€/year, assuming 6 % discount rate and 30 years cable and converter lifetime.

Table 49. Subsea cable capacity increase for meshed offshore grid, compared with radial connection only. Onshore bus names are shown with zone name in parentheses.

From bus	To bus	Length	Capacity [MW]
DE-O10	D-24 791 (DE-2)	199	3810
NL-O6	NL-O1	256	2000
NO-O1	DE-O10	229	2000
SE-O3	PL-11074 (PL-1)	109	2000
NL-O6	NL-4 610 (N)	102	2000
DE-O6	DE-O10	92	2000
DK-O3	SE-O2	8	2200
NL-O6	DE-O6	66	1500
NL-O1	BE-O1	63	1500
NL-O3	GB: 6 (GB)	203	1000
NO-O1	Nordel 5600 (NO-1)	147	1010
DK-O1	DE-O10	76	1000
DK-O3	Nordel 8500 (DK-E)	60	1000
DE-O2	DE-O1	51	1000
DE-O1	D-5 772 (DE-1)	63	946
DE-O2	SE-O1	23	1000

[11] Only an estimate for total cost were known for Borkum 2 (300 M€). A very rough simplification have been done for dividing total costs into cable costs and converter costs by assuming specific cable costs similar to the other project in the list, Oseberg oil rig.

DE-O2	DK-O4	11	1000
DK-O1	DK-81039 (DK-W)	50	240
DE-O4	D-3 770 (DE-1)	83	200
DK-O5	DE-O4	17	200
DK-O5	*Nordel: 3300 (SE-1)*	*114*	*-200*
DE-O2	*D-5 772 (DE-1)*	*114*	*-329*
SE-O2	*Nordel: 3300 (SE-1)*	*43*	*-994*
SE-O1	*Nordel: 3300 (SE-1)*	*80*	*-971*
NL-1 607 (NL)	*Nordel: 5605 (NO-1)*	*558*	*-700*
DE-O6	*D_DI 807 (DE-2)*	*155*	*-2000*
SE-O3	*Nordel: 3200 (SE-2)*	*179*	*-2000*
Nordel: 5604 (NO-1)	*D-24 791 (DE-2)*	*512*	*-1400*
DE-O10	*D-12 779 (DE-2)*	*193*	*-4810*

APPENDIX 6 – MODEL UPDATES

The study of large scale integration of wind in the European system for the future years 2015, 2020 and 2030 revealed some problems with the initial development of the UCTE/Nordel and UK power flow model. Most of these were corrected as a part of TradeWind WP3 [1].

Distribution of generator types

Since the model for UCTE is an equivalent model, where the exact location, generator type and size are unknown, some estimates were made with this respect. Based on available generators and their size in the existing model, allocation of generator types were made according to an algorithm described in [1]. After allocation of generator type every generator is scaled so that the total installed generation by type matches that are given in country-wise scenarios for installed capacity, developed as part of TradeWind WP3 [2]. The original distribution of generator type algorithm resulted in some unrealistic large and small generators, causing problems in finding an optimal solution for every hour.

The information on power plant, given by European Energy Exchange (EEX) available from their web site http://www.eex.com, was used in combination with maps of the study model developed by Bialek [13] to estimate the generation types of generators in the model for both Germany and Austria. For the other countries in UCTE, the algorithm described below was used to assign generation types to generators, except for hydro and nuclear that have already been assigned [1].

In order to find an improved and more realistic solution, a new distribution of generators type algorithm has been implemented. To get the number of installed generator types for each country the following algorithm is now used:

1. The relative installed capacity for each generation type, in a given country, is multiplied by total number of generators in that country.
2. For a generation type where the relative number is less than 1, it is set to 1.
3. For every other generator type round off is used to get an integer number generators by type. The total deviation in installed generators after 1 and 2, which will be an integer value, is either added or subtracted equally among the largest generator types, making sure there is always one generator for a specific generator type.

4. The generators in the model are then sorted for each country, using the larger generators for the generation type with most generators.

Tuning of initial water reservoir levels

Assuming that every year is hydrological identical, the ideal total use of the hydro energy is equal to the total inflow, thus the reservoir levels are the same in the start and the end. In all previous simulations it has been assumed an initial reservoir level of 60% for all hydro units, that resulted in a deviation in start and end levels for many units. The deviations increase when large improvements are being made to the grid, such as the proposed offshore super grid, as the addition of new connections removes bottlenecks for the Hydro energy going from low to higher price areas. The initial reservoir level is therefore tuned by running successive[12], full year simulations for the given year, so that start and end reservoir levels are approximate the same. This method of setting the initial reservoir levels were used in the offshore grid study in Chapter 5.

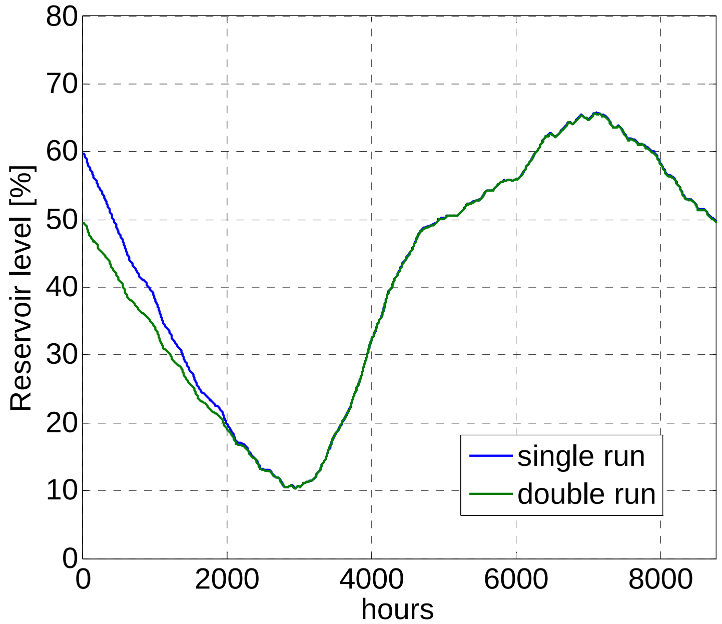

Figure 57. Reservoir level for NO-1 in 2030 with and without pre-simulation

Distribution of wind power to individual buses

In TradeWind WP3, the grid model detail was still on a zonal level, and thus, the aggregated wind farms ("wind regions") from WP2 were

[12] For the simulations in the offshore grid scenarios one full year pre-simulation was used.

allocated to the different zones according to their geographical location. As explained in [1], it was decided to increase the grid modelling detail to a full DC power flow representation. Thus, it was necessary to allocate wind power to the different buses in the power flow model. The list of wind regions and the chosen connection buses are given in Table 50. See TradeWind WP3 report [2] for Nordel bus numbering and the PowerWorld grid model of Bialek [22] for UCTE bus numbering. The locations of the wind regions are shown in Figure 58, and more detailed information, such as the installed capacity and land type can be found in [4]. For most of the wind regions it was decided to use one bus per wind region. This is a reasonable simplification since there are no internal constraints in most of the zones in the grid model. It will however result in a lower degree of freedom when finding an optimal solution, and can result in occasional wind curtailment, as shown for FR-3 (France) and HU (Hungary) in Chapter 4.8. This could have been avoided by allocating wind capacity to more buses in a zone. Since the grid model includes internal grid limitations in parts of Germany, it was decided to allocate the capacity of some the wind regions n this country to several buses (the capacity is divided evenly between the buses). This was also done for offshore wind in Netherlands, due to its proximity to North-Western Germany.

Table 50. Wind regions and the corresponding area, zone and grid bus name [2], [4], [22].

Area	Zone	Bus	Region Identifier (Node)	Country/Region
AT	AT-1	A-141009	1	Austria
BE	BE	B-15 548	2	Belgium 1
BE	BE	B-11 544	3	Belgium 2 (Offshore)
BE	BE	B_ZA 534	3	Belgium 2 (Offshore)
BG	BG	BU_STOLN	4	Bulgaria 1
BG	BG	BU_STOLN	5	Bulgaria 2
BG	BG	BU_STOLN	6	Bulgaria 3
HR	HR	CRT-1238	7	Croatia 1-1
HR	HR	CRT-1242	8	Croatia 1-2
HR	HR	CRT-1229	9	Croatia 2
CZ	CZ	CZ-71046	11	Czech Republic 1
CZ	CZ	CZ-21063	12	Czech Republic 2
CZ	CZ	CZ-31073	13	Czech Republic 3
DK	DK-E	Nordel: 8500	14	Denmark 1
DK	DK-W	DK-81039	15	Denmark 2-1
DK	DK-W	DK-11032	16	Denmark 2-2
DK	DK-W	DK-11032	17	Denmark 3-1 (Offshore)
DK	DK-E	Nordel: 8500	18	Denmark 3-2 (Offshore)
SF	FI-1	Nordel: 7000	22	Finland 1

SF	FI-2	Nordel: 7100	23	Finland 2
SF	FI-1	Nordel: 7000	24	Finland 3 (Offshore)
SF	FI-2	Nordel: 7100	25	Finland 4 (Offshore)
FR	FR-7	F-11 330	26	France 1-1
FR	FR-1	F-42 258	27	France 1-2
FR	FR-2	F-16 232	28	France 1-3
FR	FR-3	F-13 346	29	France 2
FR	FR-5	F-29 501	30	France 3-1
FR	FR-4	F-22 434	31	France 3-2
FR	FR-6	F-26 477	32	France 4
DE	DE-1	D-70 837	33	Germany 1
DE	DE-2	D-26 793	34	Germany 2
DE	DE-2	D-6 773	34	Germany 2
DE	DE-2	D-10 777	34	Germany 2
DE	DE-3	D-11 778	34	Germany 2
DE	DE-4	D-14 781	34	Germany 2
DE	DE-5	D-17 784	34	Germany 2
DE	DE-6	D-20 787	34	Germany 2
DE	D7	D-24 791	34	Germany 2
DE	D8	D_CO 795	34	Germany 2
DE	D9	D-29 796	34	Germany 2
DE	DE-10	D-30 797	34	Germany 2
DE	DE-11	D-33 800	34	Germany 2
DE	DE-12	D-37 804	34	Germany 2
DE	DE-13	D_DI 807	34	Germany 2
DE	DE-14	D-42 809	34	Germany 2
DE	DE-15	D-43 810	34	Germany 2
DE	DE-16	D-44 811	34	Germany 2
DE	DE-17	D-48 815	34	Germany 2
DE	DE-3	D-11 886	35	Germany 3
DE	DE-4	D-17 935	36	Germany 4
DE	DE-5	D-10 871	37	Germany 5-1
DE	DE-5	D_18 947	38	Germany 5-2
DE	DE-6	E-22 983	39	Germany 6
DE	DE-6	D_EI 984	39	Germany 6
DE	DE-6	D-21 975	39	Germany 6
DE	DE-6	E-21 981	39	Germany 6
DE	DE-6	D-19 959	39	Germany 6
DE	DE-6	D-19 957	39	Germany 6
DE	DE-1	D-7 774	40	Germany 7 (Offshore)
DE	DE-1	D-3 770	40	Germany 7 (Offshore)
DE	DE-2	D-24 791	41	Germany 8-1 (Offshore)
DE	DE-2	D-12 779	41	Germany 8-1 (Offshore)
DE	DE-2	D-16 783	41	Germany 8-1 (Offshore)
DE	DE-2	D-18 785	41	Germany 8-1 (Offshore)
DE	DE-2	D-20 787	41	Germany 8-1 (Offshore)
DE	DE-2	D-29 796	42	Germany 8-2 (Offshore)
DE	DE-2	D-26 793	42	Germany 8-2 (Offshore)
DE	DE-2	D_CO 795	42	Germany 8-2 (Offshore)
DE	DE-2	D-22 789	42	Germany 8-2 (Offshore)
DE	DE-2	D-27 794	42	Germany 8-2 (Offshore)
GB	GB	GB: 3	43	Great Britain 1-1

GB	GB	GB: 6	44	Great Britain 1-2
GB	GB	GB: 3	45	Great Britain 2
GB	GB	GB: 5	46	Great Britain 3-1
GB	GB	GB: 1	47	Great Britain 3-2
GB	GB	GB: 6	48	Great Britain 4-1 (Offshore)
GB	GB	GB: 3	49	Great Britain 4-2 (Offshore)
GR	GR	GR_AGRAS	50	Greece 1-1
GR	GR	GR_AGRAS	51	Greece 1-1
GR	GR	GR_AGRAS	52	Greece 2 (Offshore)
HU	HU	H-201189	53	Hungary 1
IT	IT-1	CASS 662	54	Italy 1
IT	IT-3	MONT 726	55	Italy 2
IT	IT-3	LATI 737	56	Italy 3
IT	IT-3	FERO 753	57	Italy 4
IT	IT-3	CHIA 765	58	Italy 5
LU	LU	LX-1 604	63	Luxembourg
NL	NL	NL-1 619	65	Netherlands 1
NL	NL	NL-1 623	66	Netherlands 2 (Offshore)
NL	NL	NL-1 621	66	Netherlands 2 (Offshore)
NL	NL	NL_B 629	66	Netherlands 2 (Offshore)
NL	NL	NL-4 610	66	Netherlands 2 (Offshore)
NL	NL	NL-3 609	66	Netherlands 2 (Offshore)
NO	NO-1	Nordel: 6000	67	Norway 1
NO	NO-2	Nordel: 6500	68	Norway 2
NO	NO-2	Nordel: 6500	69	Norway 3-1
NO	NO-3	Nordel: 6700	70	Norway 3-2
NO	NO-3	Nordel: 6700	71	Norway 3-3
NO	NO-1	Nordel: 5600	72	Norway 4 (Offshore)
NO	NO-2	Nordel: 6500	73	Norway 5 (Offshore)
NO	NO-2	Nordel: 6500	74	Norway 6-1 (Offshore)
NO	NO-3	Nordel: 6700	75	Norway 6-2 (Offshore)
NO	NO-3	Nordel: 6700	76	Norway 6-3 (Offshore)
PL	PL-1	PL-11085	77	Poland 1
PL	PL-2	PL-81160	78	Poland 2
PT	PT	P-11 10	79	Portugal 1
PT	PT	P-12 11	80	Portugal 2
PT	PT	P-23 22	81	Portugal 3
PT	PT	P-24 23	82	Portugal 4
PT	PT	P-26 24	83	Portugal 5
IE	IE	IE: 7	84	Republic of Ireland and Northern Ireland 1
IE	IE	IE: 7	85	Republic of Ireland and Northern Ireland 2
IE	IE	IE: 7	86	Republic of Ireland and Northern Ireland 3
IE	IE	IE: 7	87	Republic of Ireland and Northern Ireland 4
IE	IE	IE: 7	88	Rep of Ireland and Northern Ireland 5(Offshore)
IE	IE	IE: 7	89	Rep of Ireland and Northern Ireland 6(Offshore)
RO	RO	RO_PORTF	90	Romania 1
RO	RO	RO_PORTF	91	Romania 2
RO	RO	RO_PORTF	92	Romania 3
RO	RO	RO_PORTF	93	Romania 4
RO	RO	RO_PORTF	94	Romania 5
RO	RO	RO_PORTF	95	Romania 6
RO	RO	RO_PORTF	96	Romania 7 (Offshore)

RS	RS	SC_KOSOV	97	Serbia
SK	SK	SK-21217	98	Slovakia 1
SK	SK	SK-11212	99	Slovakia 2
SK	SK	SK-31197	100	Slovakia 3
SI	SI	SV-31221	101	Slovenia 1
SI	SI	SV-71225	102	Slovenia 2
ES	ES-4	E-19 214	103	Spain 1-1
ES	ES-4	E-18 205	104	Spain 1-2
ES	ES-4	E-18 211	105	Spain 1-3
ES	ES-2	E-62 86	106	Spain 2-1
ES	ES-2	E-10 130	107	Spain 2-2
ES	ES-2	E-11 138	108	Spain 2-3
ES	ES-1	E-9 33	109	Spain 3
ES	ES-1	E-16 40	111	Spain 5
ES	ES-3	E-14 170	112	Spain 6
ES	ES-1	E-81 105	113	Spain 7-1
ES	ES-1	E-75 99	114	Spain 7-2
ES	ES-4	E-13 155	115	Spain 7-3
ES	ES-2	E-69 93	116	Spain 8-1
ES	ES-2	E-11 143	117	Spain 8-2
ES	ES-3	E-12 152	118	Spain 9-1
ES	ES-3	E-16 185	119	Spain 9-2
ES	ES-4	E-15 178	120	Spain 10
ES	ES-1	E-24 48	121	Spain 11
ES	ES-1	E-27 51	122	Spain 12
ES	ES-3	E-13 156	123	Spain 13
ES	ES-3	E-17 200	124	Spain 14
ES	ES-2	E-41 65	125	Spain 15
ES	ES-1	E-17 41	126	Spain 16
ES	ES-1	E-14 38	127	Spain 17-1 (offshore)
ES	ES-4	E-19 216	128	Spain 17-2 (offshore)
SE	SE-2	Nordel: 3359	129	Sweden 1
SE	SE-2	Nordel: 3000	130	Sweden 2
SE	SE-3	Nordel: 3249	131	Sweden 3-1
SE	SE-3	Nordel: 3115	132	Sweden 3-2
SE	SE-1	Nordel: 3300	133	Sweden 4-1 (Offshore)
SE	SE-1	Nordel: 3300	134	Sweden 4-2 (Offshore)
SE	SE-2	Nordel: 3200	135	Sweden 5 (Offshore)
SE	SE-3	Nordel: 3245	136	Sweden 6-1 (Offshore)
SE	SE-3	Nordel: 3115	137	Sweden 6-2 (Offshore)
CH	CH-1	CH-1 568	138	Switzerland

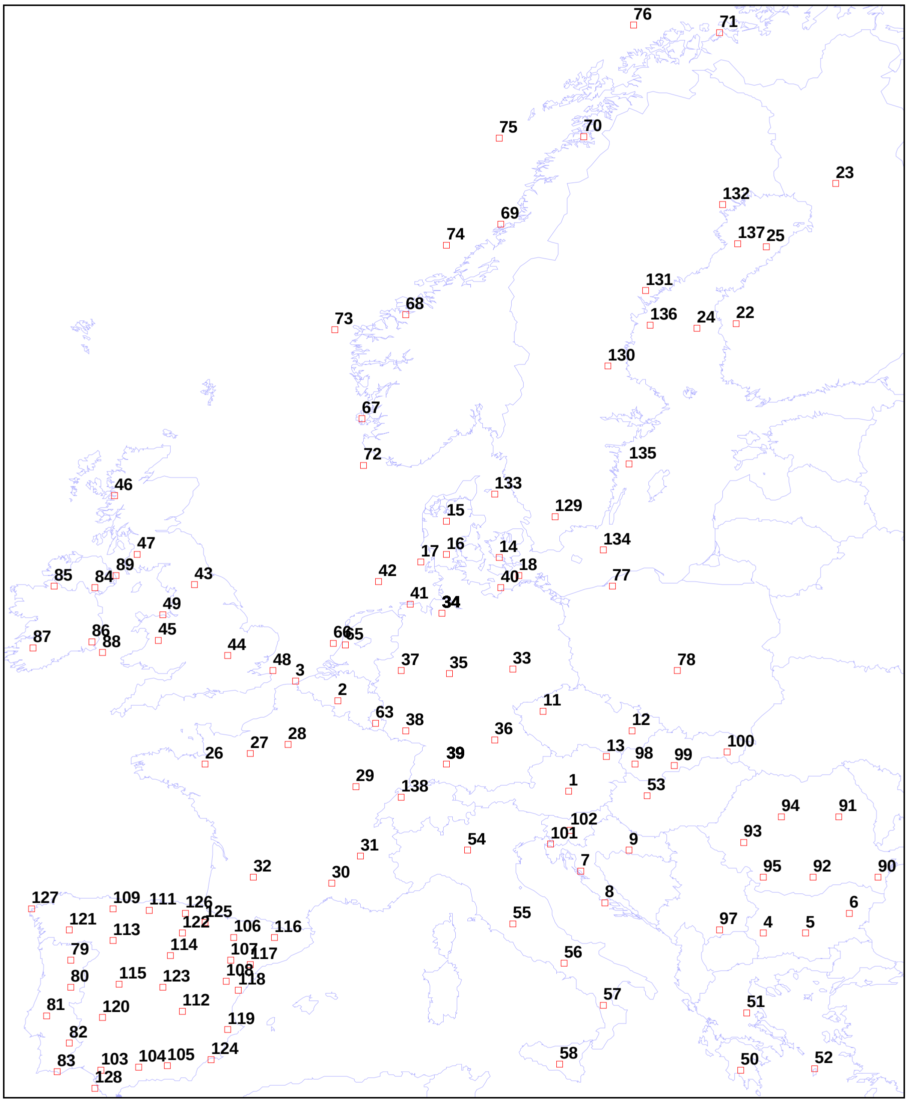

Figure 58. Locations and numbering of wind regions from [4].

APPENDIX 7 – PLANS FOR GRID EXTENSIONS IN EUROPE

This Appendix gives the results of a quick scan of planned grid extensions within Europe, based on the expansion plans published by UCTE, Nordel and many national TSOs.

A.1 UCTE interconnection projects

In this chapter an overview of the majority of planned or studied projects within the UCTE area will be given. A total schematic overview and capacities (where known) are given in the UCTE Transmission Development Plan edition 2008 [5]. All projects are sorted by region and by country. Some countries are mentioned multiple times. This means a country has interconnections within different UCTE regions.

A.1.1 UCTE region Central West

This region consists of the following countries: Belgium, Germany, Luxembourg, France and The Netherlands.

Belgium

Belgium is expected to have a shortage of energy production within the next ten to fifteen years. Therefore Belgium is expanding its interconnection capacity drastically. New built lines and upgrades are being executed to raise the net transfer capacity from 2250 to 3200 MW. At the moment, there are no interconnections to Germany. Studies are started to investigate the impacts of a possible interconnection. No concrete plan is available.

Plans for additional interconnections to The Netherlands are being studied as well and a study is started to investigate the possibility of a HVDC cable connection to the United Kingdom.

Germany

A Germany-France interconnection is available for emergency situations only, but a study is started to investigate an upgrade. Permitting procedures are being done for a new 400 kV interconnection between The Netherlands and Germany. A new HVDC link to Norway is planned to be operational after 2015 and an upgrade of the AC link to Denmark is expected.

Luxembourg

There are plans for a new interconnection between Luxembourg and Belgium, but not expected to be built in the near future. An interconnection to Germany is more likely. The industrial grid operator SOTEL is planning to build a 225 kV interconnection to France.

Netherlands

A new 1320 MW submarine HVDC link with the United Kingdom is planned to be operational in 2010. Phase shifter transformers will be installed in the spring 2008 at the Dutch-Belgian border in order to improve control of power flows. These phase shifters are also influencing the power flow between Netherlands and Germany. Two new shifters will be installed in the Diele (DE) substation to increase transfer capacity between Netherlands and Germany.

A new 400 kV line between Doetinchem and Niederrhein will also increase interconnection capacity and will be expected earliest in the year 2013.

A.1.2 UCTE region central East

This region consists of the following countries:
Germany, Poland, Czech Republic, Austria, Slovenia, Hungary and Slovakia

Austria

A new 400 kV connection is planned to be operational in 2008 between Austria and the Czech Republic. Furthermore, two interconnections to Germany will be upgraded from 220 kV to 380 kV in order to improve transport abilities. One new line between Austria and Germany is being studied, but will not be expected before 2017. The interconnection between Austria and Hungary is being completed now and no new projects are foreseen in the near future. A study is performed for a new interconnection between Austria and Slovakia and is not to be expected before 2020.

Slovakia

A study is performed for a new 400 kV line to Hungary, but will not be operational before 2015. A new 400 kV interconnection to Poland is planned in 2018, but Poland has to upgrade its network first in order to handle this connection. The interconnection to Ukraine will be upgraded to 400 kV after 2015.

Germany

A double 380 kV overhead line to the Czech Republic is foreseen in 2016 in order to handle large amounts of wind power. A 220 kV line to Poland will be converted into a 400 kV line after 2015. A third connection to Poland will be installed after 2015, but Poland has to upgrade its network first in order to handle this connection.

A.1.3 UCTE region central South

This region consists of the following countries:
France, Switzerland, Austria, Slovenia and Italy

Italy

A phase shifting transformer will be placed in short term between Italy and Austria to increase capacity. Another project is to build a new 380 kV line to Austria, but this project is delayed due to the environmental impact assessment. Some other projects of lower voltages are being processed as well. This means many reinforcements between Italy and Austria will be built in the (near) future.

A HVDC project is being studied to use the Fréjus tunnel as a 1000 MW interconnection between France and Italy. Some other smaller projects are foreseen in the short term. A HVDC link to Tunisia is planned to be operational in 2011. This 1000 MW connection will be used to transport locally produced energy to Europe.

To avoid congestion at the Italian-Slovenian border, a new 380 kV overhead line is planned. This connection will improve the reliability and security of the grids of both countries.

A.1.4 UCTE region South East

This region consists of the following countries:
Italy, Slovenia, Bosnia Herzegovina, Greece, Hungary, Romania, Bulgaria, Albania

The main concern of these countries is not the interconnections, but the local national connections. These countries do not have sufficient capacity internally in order to handle the big interconnectors; therefore many projects have an uncertain commissioning date. Most of the projects are under investigation. Not all projects are mentioned here, but a total overview of projects can be found in the UCTE Transmission Development Plan.

Hungary

The construction of a new 400 kV interconnection between Hungary and Romania will improve the security of the entire interconnection operation and offer a reserve path for the export – import contracts to the western electricity market. The new 400 kV interconnection between Hungary and Croatia is expected to increase security as well. The import capacity of Croatia and surrounding countries from central Europe and Ukraine is also expected to be increased. The first interconnection between Slovenia and Hungary via a new 400 kV double line should be completed by 2011.

Albania

A HVDC link from Albania to Italy is being investigated, but the Albanian network needs reinforcements first. A 400 kV overhead line to Montenegro is under construction. This link is mainly for improving reliability and redundancy.

Greece

The interconnection with Italy has increased the reliability of the Greek system, while a new link for energy trading has been established between south eastern Europe and the rest of Europe. A preliminary study is foreseen to assess the possibility of a second DC link between Italy and Greece.

A new line from Greece to Bulgaria is under consideration. This line is expected to not only increase transfer capacity, but also improve power system security and stability when Turkey will be connected to UCTE in the future.

Serbia

Six options for interconnections from Serbia to Romania are being studied, and only three are to be further investigated. These projects are not to be expected within the short term.

Turkey

A new 400 kV overhead line will be built between Greece and Turkey in order to synchronize the Turkish network with the UCTE zone. This connection will be available in 2008.

Nowadays, there are two 400 kV overhead lines between Bulgaria and Turkey, and will be put into operation when the synchronous work between Turkey and the UCTE is possible. A HVDC submarine cable is taken into consideration in 2018 between Turkey and Romania.

A.1.5 UCTE region South West

This region consists of the following countries:
Portugal, Spain and France

France – Spain interconnection

At present there are only four lines between France and Spain, and the last one was built in 1982. These lines are facing continuous congestions. France and Spain have a shared goal to increase their interconnection capacity to 4000 MW. In order to realize this, two new 400 kV double circuit line have to be built. The first one is classified as a priority project by the European Commission. The recommendations regarding this line are expected at the end of June 2008. The second line is still under investigation.

Portugal – Spain interconnection

A new line is expected to be operational in 2009, as well as some changes in the topology of the existing 220 kV lines in the same area. In the long term, two new lines are planned: one in the north and one in the south. This will result in a total transfer capacity of 3000 MW.

Spain – Morocco interconnection

The second circuit 400 kV with AC submarine technology was commissioned in June 2006. No other projects are currently scheduled, although in the future new connections with Morocco and/or Algeria can be considered.

A.2 British Isles (Great Britain, Northern Ireland and Ireland)

There are not many ongoing or planned projects in Great Britain. EirGrid, the national grid operator of Ireland, is planning two projects to facilitate cross-border sharing of electricity to promote better competition and to ensure a future secure supply of electricity throughout the North East. One project is an 80 km long 400 kV power line – the new North South interconnector from Ireland to Northern Ireland. The second one is a 58 km 400 kV power line to facilitate the power transportation capacity of the first project within Ireland. There is no power and commissioning date mentioned in the EirGrid publications.

There is also a plan for a 130 km 500 MW HVDC east-west interconnector between England and Ireland. Studies are still being performed, but if the current plans will continue, the line will be in operation around 2012. Another big project for Ireland is a 400 kV interconnection to Northern Ireland, this project is foreseen to be completed around 2012 as well. Possible interconnectors from England to the European mainland are already mentioned in the past sections.

A.3 Nordel

Nordel represents the TSOs of Norway, Sweden, Finland and Denmark. The national grid operators are planning or executing five projects in order to improve or expand their interconnection capacity. The projects and their status are listed below.

Fenno-Skan 2

Fenno-Skan 2 is a submarine HVDC connection from Finland to Sweden. The new cable will be laid in parallel with the existing cable. On the Swedish side, a 70 km DC overhead line will be built to a new substation where the converter station will be placed. The planned capacity is 800 MW. The submarine cable manufacturing and the converter station project execution will start in 2009. The commissioning will be expected late 2011.

Nea-Järpströmmen

This project comprises a new 400 kV (750 MW) transmission line between Järpströmmen (Sweden) and Nea (Norway). The new 100 km line will replace the existing 300 kV line. The start of construction will start in 2008 and commissioning will be expected mid 2009.

South Link

The transmission capacity to southern Sweden is proposed to be improved by means of a new connection between Hallsberg and a new site outside Hörby in Skåne. The length of the 1200 MW connection will be about 400 km. Two technical solutions will be used: VSC HVDC with underground cable for the southern half and conventional 400 kV AC overhead lines for the northern part. This connection will be a part of the South-West link with an added connection to Norway. The permits from authorities will be expected in 2011 and the commissioning around 2014.

Skagerrak IV

The existing 1000 MW Skagerrak interconnection connects Kristiansand in Norway with Tjele in Denmark. The TSOs are examining the possibilities for increasing the capacity with 600 MW by laying down a fourth cable along the existing three cables. The parties aim at a conclusion and applying for public approvals in summer 2008. The earliest date of commissioning will be 2014.

Great Belt

The project comprises a HVDC link between Eastern Denmark (Zealand - a part of the Nordel synchronous area) and Western Denmark (Funen - a part of the UCTE synchronous area). The link will be connected to the grid in Herslev on Zealand and Fraugde on Funen. The connection will be a 600 MW conventional HVDC link. The construction started in the second half of 2007 and the commissioning will take place in 2010.